SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

TEXAS INDUSTRIAL ENERGY CONSUMERS' REPLY BRIEF

July 1, 2021

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GLOSSARY OF ACRONYMS

1CP	Single Coincident Peak
A&E/4CP	Average and Excess Demand, Four Coincident Peak
ADFIT	Accumulated Deferred Federal Income Taxes
AEP	American Electric Power
ALJ	Administrative Law Judge
ATC	Approved Transmission Charges
BTMG	Behind the Meter Generation
CAPM	Capital Asset Pricing Model
CARD	Cities Advocating Reasonable Deregulation
CCGT	Combined Cycle Gas Turbine
CCOSS	Class-Cost-of-Service Study
CoL	Conclusion of Law
DCF	Discounted Cash Flow
DCRF	Distribution Cost Recovery Factor
DHPS	Dolet Hills Power Station
EECRF	Energy Efficiency Cost Recovery Factor
ERCOT	Electric Reliability Council of Texas
ETEC/NTEC	East Texas Electric Cooperative/Northeast Texas Electric Cooperative
ETI	Entergy Texas, Inc.
ETSWD	East Texas Salt Water Disposal Company
FERC	Federal Energy Regulatory Commission
FoF	Finding of Fact
GAAP	Generally Accepted Accounting Principles
GCRR	Generation Cost Recovery Rider
GDP	Gross Domestic Product
IM	Integrated Marketplace
IRP	Integrated Resource Plan
LLP	Large Lighting and Power

LLP-T	Large Lighting and Power-Transmission
MISO	Midcontinent Independent System Operator
MW	Megawatt, a unit of power
MWh	Megawatt-Hour, a unit of energy
NBV	Net Book Value
NOLC	Net Operating Loss Carryforward
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OP	Ordering Paragraph
OPUC	Office of Public Utility Counsel
PFD	Proposal For Decision
PPA	Purchased Power Agreement
PUC, or the "Commission"	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act, Tex. Util. Code §§ 11.001 *et seq.*
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
REC	Renewable Energy Credit
ROE	Return On Equity
S&P	Standard & Poor's
SPP	Southwest Power Pool
SSGL	Synchronized Self-Generation Load
SWEPCO	Southwestern Electric Power Company
TCJA	Tax Cuts and Jobs Act of 2017
TCRF	Transmission Cost Recovery Factor
TIEC	Texas Industrial Energy Consumers
WACC	Weighted-Average Cost of Capital

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I. Introduction/Summary [Preliminary Order (PO) Issues 1, 2, and 3]

Texas Industrial Energy Consumers (TIEC) respectfully submits this reply to the briefs of Southwestern Electric Power Company (SWEPCO) and other parties.

II. Invested Capital - Rate Base [PO Issues 4, 5, 10, 11, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22]

A. Generation, Transmission, and Distribution Capital Investment [PO Issues 4, 5, 10, 11, 13, 14, 15, 16]

1. Dolet Hills Power Station [PO Issues 67, 68, 69, 70, 71]

The Commission should reject SWEPCO's proposal to recover not only all of its remaining investment in Dolet Hills Power Station (DHPS) in four years, but to also recover up to four years of operations and maintenance (O&M) and other expenses for a plant that will be retired less than a year after the effective date of rates in this case. SWEPCO's proposal is unfair to ratepayers and inconsistent with Commission precedent. The only way in which SWEPCO can justify its inequitable proposal is to incorrectly assert that the only alternative is an even more inequitable outcome.[1] The Commission should treat DHPS either (1) as an operational plant and maintain the current useful life of 2046, or (2) as a retired plant and take all costs associated with DHPS out of rates, and place the undepreciated balance into a regulatory asset to be amortized through 2046 without a return.[2] Under the facts and circumstances surrounding DHPS presented in this case,

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[1] SWEPCO's In. Br. at 10-11.

[2] TIEC Ex. 4, Direct Testimony and Exhibits of Billie S. LaConte at 9-11, 13-14 (LaConte Dir.).

the Commission should treat DHPS as a retired plant.[3]

a. There is no requirement that the entire remaining balance in DHPS be depreciated in a single year.

SWEPCO's DHPS excess accumulated deferred federal income tax (ADFIT) offset proposal is built upon the faulty premise that DHPS would otherwise have to be depreciated through the end of 2021.[4] As TIEC set forth in detail in its initial brief, that premise is incorrect.[5] PURA[6] directs the Commission to set just and reasonable rates.[7] The unexpected early retirement of a generating facility can create issues of equity (including intergenerational equity), and the Commission has the discretion to set the depreciable life of an asset to achieve its statutory mandate. For example, the Commission in Docket No. 40443 maintained the preexisting retirement date of 2040 for Welsh Unit 2, even though there was a federal consent decree requiring SWEPCO to retire that plant no later than December 31, 2016.[8]

In support of its erroneous position, SWEPCO cites to the testimony of ETEC/NTEC[9] witness Mr. Hunt,[10] but Mr. Hunt made clear at the hearing that Federal Energy Regulatory Commission (FERC) accounting and generally accepted accounting principles (GAAP) do not override the Commission's directive to set just and reasonable rates.[11] That is consistent with the Commission's decision in Docket No. 46449, where it explicitly stated that accounting rules do

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[3] *See generally* TIEC's In. Br. at 8-11.

[4] SWEPCO's In. Br. at 10-11.

[5] TIEC's In. Br. at 6-7.

[6] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001 et seq.

[7] PURA § 36.003(a).

[8] TIEC Ex. 4, LaConte Dir. at 9-10.

[9] East Texas Electric Cooperative/Northeast Texas Electric Cooperative.

[10] SWEPCO's In. Br. at 10.

[11] Tr. at 311:14-313:14 (Hunt Cross) (May 20, 2021).

not control ratemaking decisions.[12]

Nor does the Commission's cost-of-service rule require depreciating DHPS by 2021 as SWEPCO argues.[13] As an initial matter, SWEPCO's interpretation proves too much, as SWEPCO's own excess ADFIT offset proposal would violate its interpretation of the cost-of-service rule since it simultaneously amortizes $39 million of the undepreciated balance immediately and $6.4 million of the undepreciated balance over four years—neither of which are consistent with straight-line depreciation through the end of 2021.[14] Moreover, the relevant portion of the cost-of-service rule explicitly states that other methods of depreciation may be used when it is determined that such depreciation methodology is a more equitable means of recovering the cost of the plant.[15] SWEPCO witness Mr. Baird acknowledged at the hearing that setting depreciation rates to recover the entire remaining balance in DHPS through the end of 2021 would create an inequitable result.[16] If the Commission determines that DHPS should be treated as an operational plant, then the current depreciable life of 2046 should be maintained, which is not only a more equitable depreciation methodology but is also supported by Commission precedent established in Docket No. 40443.

b. SWEPCO's excess ADFIT offset proposal is inequitable to ratepayers.

SWEPCO's excess ADFIT offset proposal should be rejected because it would allow SWEPCO to recover $39 million of the undepreciated balance in DHPS immediately while depriving ratepayers of a $39 million refund to which they are entitled. As SWEPCO notes in its brief, ADFIT is properly included as an offset to rate base.[17] That is because it represents taxes

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[12] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Proposal for Decision (PFD) at 94 (Sept. 22, 2017), *adopted by* Order on Rehearing (Mar. 19, 2018).

[13] SWEPCO's In. Br. at 10-11.

[14] *Cf* Tr. at 473:2-5 (Baird Cross) (May 20, 2021).

[15] 16 T.A.C. § 25.231(b)(1)(B).

[16] Tr. at 473:15-476:1 (Baird Cross) (May 20, 2021).

[17] SWEPCO's In. Br. at 11.

that ratepayers have paid for in rates that, due to timing differences, the utility has not paid yet.[18] However, ***excess*** ADFIT represents taxes that ratepayers have paid for in rates that the utility will never pay because of the reduction in tax rates resulting from the Tax Cuts and Jobs Act of 2017 (TCJA).[19] Thus, excess ADFIT is not properly included in rate base and should be returned to customers,[20] which SWEPCO does not dispute.[21] Nevertheless, instead of returning the $39 million excess ADFIT balance to customers, SWEPCO proposes to use it to pay off a portion of the remaining balance in DHPS, which results in SWEPCO immediately recovering that $39 million of the undepreciated balance. While SWEPCO bemoans the fact that Staff and intervenors do not acknowledge that the offset proposal immediately reduces rate base, SWEPCO fails to mention that its proposal deprives ratepayers of a $39 million refund.[22] The only way SWEPCO shows a benefit for its proposal is by arguing that the alternative is to set rates based on depreciating $45.4 million for DHPS in a single year. However, as explained above and in TIEC's initial brief, that treatment is not required, and would be inconsistent with Commission precedent. SWEPCO's excess ADFIT proposal should be rejected.

c. The facts of this case warrant removing DHPS from rate base and treating it as a retired plant.

The Commission should treat DHPS as either an operational plant or a retired plant and follow its Welsh Unit 2 precedent in either instance, as laid out in Ms. LaConte's testimony.[23] In its pre-filed direct case, SWEPCO provided scant evidence of the prudence of retiring DHPS and did not explicitly request a prudence finding.[24] SWEPCO has now made clear in its initial brief

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[18] TIEC Ex. 4, LaConte Dir. at 14-15.

[19] *Id.* at 15.

[20] *Id.*

[21] SWEPCO's In. Br. at 11.

[22] *Id.*

[23] TIEC Ex. 4, LaConte Dir. at 9-13.

[24] *See generally* SWEPCO Ex. 1, Rate Filing Package Schedules & Workpapers at Petition; SWEPCO Ex. 4, Direct Testimony of Thomas P. Brıce (Brice Dir.); SWEPCO Ex. 4A, Workpapers to the Direct Testimony of Thomas Brice (providing testimony from another jurisdiction as support of the prudence of retirıng DHPS) (Brice Dir. Workpapers).

that it is in fact requesting a prudence finding for its decision to retire DHPS, citing to the Commission's Preliminary Order as support.[25] In rebuttal testimony, SWEPCO witness Mr. Brice contended that the Commission's Preliminary Order made DHPS distinguishable from Welsh Unit 2 in Docket No. 40443, claiming that the Commission based its decision in that case on the fact that it also deferred a prudence finding for Welsh Unit 2.[26] However, this reading of Docket No. 40443 is belied by the Commission's findings in that proceeding, which stated: "The retirement of Welsh Unit 2 has not yet occurred. Consequently, it is inappropriate to consider the unit's retirement costs before it actually happens."[27]

Moreover, if a plant is considered to be prudently retired, then it is not appropriate to treat that plant as operational in setting rates. TIEC submits that under the facts and circumstances surrounding DHPS presented in this case, it is appropriate to treat DHPS as a retired plant. TIEC acknowledges that the cost-of-service rule generally requires a plant to be retired before the rate year in order to remove it from rate base. However, for the many reasons set forth in detail in TIEC's initial brief, there are grounds for a good-cause exception in this proceeding.[28] Additionally, TIEC submits that Staff's,[29] Office of Public Utility Counsel's (OPUC)[30] and Cities Advocating Reasonable Deregulation's (CARD)[31] creative approaches of using a regulatory liability account or rider to allow a return through the end of the useful life (and no longer) could also be warranted under the specific facts of this proceeding.

The Commission should remove DHPS from rates and place the remaining undepreciated

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[25] SWEPCO's In. Br. at 5; *see also* SWEPCO Ex. 33, Rebuttal Testimony of Thomas P. Brice at 15-16 (Brice Reb.).

[26] SWEPCO Ex. 33, Brice Reb. at 15.

[27] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 40443, Order on Rehearing at FoF 124 (Mar. 6, 2014). Additionally, the Commission's Preliminary Order is by its own terms non-binding with respect to the issues to be addressed. Preliminary Order at 17-18 (Dec. 17, 2020)

[28] TIEC's In. Br. at 8-11.

[29] Staff's In. Br. at 7-8.

[30] OPUC's In. Br. at 3-6.

[31] CARD's In. Br. at 6.

balance in a regulatory asset to be amortized, without a return, through the current useful life of 2046. While SWEPCO complains that this treatment is unfair and asymmetrical,[32] it is consistent with the treatment of Welsh Unit 2 in Docket No. 46449, in which the Commission found that this approach properly balanced the interest of ratepayers and the utility with respect to an early-retired plant. Further, the argument for this treatment has only gotten stronger since that case, as the Commission has now adopted a generation cost recovery rider (GCRR) mechanism, which allows a utility to begin recovering its investment in a generating facility on the day of commercial operation without accounting for any offsetting changes in the utility's other generating assets, including accumulated depreciation or retired plants.[33]

2. Retired Gas-Fired Generating Units [PO Issue 13]

The Commission should adopt the recommendation of Staff witness Ms. Stark and treat SWEPCO's retired gas plants in the same way that it treated the undepreciated balance of Welsh Unit 2 in SWEPCO's last rate case. In arguing to depart from this Commission precedent, SWEPCO raises many of the same arguments that the Commission explicitly rejected in Docket No. 46449,[34] including that the treatment is required by FERC accounting guidelines.[35]

SWEPCO also claims that Welsh Unit 2 was not the first utility generating plant to retire with some amount of undepreciated value, though SWEPCO cannot identify any case where the Commission made a finding that a utility should earn a return on the undepreciated balance of a retired plant.[36] Instead, SWEPCO points to the treatment of Lieberman Unit 1 in Docket No. 46449.[37] However, SWEPCO provides no cite for how Lieberman Unit 1 was treated in Docket

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[32] SWEPCO's In. Br. at 8-10.

[33] 16 T.A.C. § 25.248; *see also Rulemaking Related to Generation Cost Recovery Rider (GCRR)*, Proj. No. 50031, Order Adopting New §25.248 as Approved at the July 2, 2020 Open Meeting at 12-15 (July 7, 2020).

[34] SWEPCO's In. Br. at 13.

[35] Docket No. 46449, PFD at 87-88, 93-94.

[36] SWEPCO's In. Br. at 14.

[37] *Id.*

No. 46449.[38] Nor does SWEPCO provide any information about the treatment of Lieberman Unit 1, such as the magnitude of the undepreciated balance.[39] Moreover, the issue of the ratemaking treatment for Lieberman Unit 1 was never raised in that proceeding. Notably, SWEPCO explicitly presented in its initial application in Docket No. 46449 a request to earn a return on the remaining balance of Welsh Unit 2.[40] SWEPCO's request was limited to Welsh Unit 2, and there is not a single mention of the remaining balance in Lieberman Unit 1 in the PFD or Final Order in that proceeding.[41] Now, in this case, SWEPCO cites the Commission's silence on an issue that was never raised to somehow be evidence of longstanding Commission precedent to allow a return on the undepreciated balance of a retired plant.

SWEPCO's attempt to recast the Commission's decision in Docket No. 46449 should be rejected. The Commission made clear in Docket No. 46449 that the statute, not accounting, is what governs ratemaking, and that PURA does not allow a utility to earn a return on a plant that is no longer used and useful.[42] Retired plants are not used and useful, and therefore utilities may not earn a return on their undepreciated balance.[43] Under the Commission's decision in Docket No. 46449, there is no basis for distinguishing SWEPCO's recently retired gas plants from Welsh Unit 2, and they should be treated in the same manner.

Indeed, SWEPCO appears to acknowledge that it is requesting a departure from Commission precedent by making the policy argument that disallowing a return would incentivize parties to recommend extending the depreciable lives of generating plants in order to leave large

[38] *Id.*

[39] *Id.*

[40] Docket No. 46449, PFD at 87 & n.293 (citing SWEPCO's then-CEO Venita McCellon-Allen's direct testimony for the proposition that "SWEPCO proposes to record this retirement by crediting Plant in Service with the original cost of Welsh Unit 2 and debiting Accumulated Depreciation with the same amount").

[41] *See generally* Docket No. 46449, PFD; Docket No. 46449, Order on Rehearing. The only mention of the Lieberman Units in the PFD was for an unrelated issue having to do with an adjustment to normalize test-year production maintenance expense. Docket No. 46449, PFD at 198.

[42] Docket No. 46449, PFD at 94; Docket No. 46449, Order on Rehearing at FoFs 65-71.

[43] Docket No. 46449, PFD at 94.

undepreciated balances.[44] This alleged moral hazard is a strawman. The Commission, not the parties, determines the appropriate depreciable life for a generating asset. SWEPCO points to DHPS as an example, but the useful life of DHPS has always been set at 60 years, and it is only because of SWEPCO's recent decision to retire the plant 25 years early that there remains a large undepreciated balance.[45] Additionally, the Commission's prescribed treatment for retired plants strikes an equitable balance between ratepayers and shareholders by recognizing that shareholders should recover their investment, but also that it is not just or reasonable for ratepayers to pay a return on plant that is no longer used or useful in serving them. The undepreciated balance of SWEPCO's retired gas plants should be treated in accordance with the precedent established for Welsh Unit 2 in Docket No. 46449.

C. Accumulated Deferred Federal Income Tax [PO Issues 20]

1. Net Operating Loss ADFIT

Upon review of the briefs, TIEC agrees with Staff's recommendation to reject SWEPCO's adjustment to add $455,122,490 to rate base for its net operating loss carryforward (NOLC) ADFIT balance.[46] Staff's recommendation prevents SWEPCO from double-earning a return on the NOLC ADFIT balance that SWEPCO has exchanged for cash and used to fund rate base, and therefore should be adopted.[47] As Staff explained in its initial brief, SWEPCO acknowledged in rebuttal testimony that it uses cash payments it receives in exchange for its NOLC ADFIT balance under the tax allocation agreement to reduce the capital that is needed to fund plant investment.[48] As a result of that arrangement, SWEPCO needs less debt and equity capital.[49] In other words, up to $455,122,490 of SWEPCO's rate base is not actually funded by debt or equity capital, but by a

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[44] SWEPCO's In. Br. at 14.

[45] Tr. at 105:20-106:22 (Brice Cross) (May 19, 2021).

[46] Staff's In. Br. at 13-30.

[47] *Id.* at 18-22.

[48] *Id.* at 18.

[49] *Id.*

cash payment that SWEPCO received in exchange for its NOLC ADFIT balance.[50] Thus, by making an adjustment to add an additional $455,122,490 to rate base to reflect the NOLC ADFIT, SWEPCO will double-earn a return on the amount of the NOLC ADFIT payments that it used to fund rate base.[51] Just as it would be inappropriate for SWEPCO to continue to earn a return on a plant that it sold for cash, it is inappropriate for SWEPCO to earn a return on the NOLC ADFIT balance that it exchanged for a cash payment.[52] SWEPCO claims in its brief that Mr. Hodgson demonstrated in his direct testimony that SWEPCO's adjustment results in the same rates as a similarly situated utility without a tax allocation agreement.[53] But that comparison misses the point. A similarly situated utility without a tax allocation agreement would not have received a cash payment for its NOLC ADFIT balance, and that distinction is not accounted for in Mr. Hodgson's examples.[54] SWEPCO's proposed adjustment to add the $455,122,490 NOLC ADFIT balance to rate base ignores that economic reality and should be rejected.

2. Excess ADFIT

SWEPCO's excess ADFIT offset proposal for DHPS should be rejected and the $39 million excess ADFIT balance should be returned to ratepayers through a one-year refund, as recommended by Ms. LaConte.[55] The refund should be allocated among the classes consistent with the allocation set forth in Mr. Pollock's testimony,[56] and should earn carrying costs at SWEPCO's weighted-average cost of capital (WACC) starting with the effective date of rates in this case.[57] SWEPCO's brief does not disagree that a refund is appropriate if the excess ADFIT

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[50] *Id.*

[51] Staff Ex. 3, Direct Testimony of Ruth Stark at 39-41 (Stark Dir.).

[52] *Id.* at 39-40.

[53] SWEPCO's In. Br. at 25-26.

[54] SWEPCO Ex. 45, Rebuttal Testimony of David A. Hodgson at 15-16 (Hodgson Reb.). In Mr. Hodgson's Example 1, which is a similarly situated utility without a tax sharing agreement, the utility does not exchange its NOLC ADFIT balance for a cash payment. *Id.* That difference is critical.

[55] TIEC Ex. 4, LaConte Dir. at 14-17.

[56] TIEC Ex. 1, Direct Testimony and Exhibits of Jeffry C. Pollock at 40-41 (Pollock Dir.)

[57] SWEPCO Ex. 36, Rebuttal Testimony of Michael A. Baird at 25-26 (Baird Reb.).

offset proposal is rejected.[58]

E. Regulatory Assets and Liabilities [PO Issues 19, 21, 22, 41, 50]

1. Self-Insurance Reserve [PO Issues 19 and 40]

SWEPCO has yet to present the cost-benefit analysis required to establish a self-insurance reserve. But even if it had, the utility's proposed target reserve is inflated and, if approved, should be approved at a reduced level.

SWEPCO's initial brief makes clear that it has not met the threshold requirements of 16 T.A.C. § 25.231(b)(1)(G), which mandates that the utility present a cost-benefit analysis showing that self-insurance is in the public interest. As set forth in TIEC's initial brief, Mr. Wilson never provided a quantitative cost-benefit analysis establishing that self-insurance is less costly or more beneficial than private insurance, and his analysis only included theoretical, generic cost categories.[59]

Instead, SWEPCO points to Mr. Wilson's testimony that commercial insurance in Texas is always going to be more expensive than self-insurance and that it is SWEPCO's experience that commercial insurance is significantly more expensive than self-insurance.[60] But if this type of conclusory testimony was sufficient to show that self-insurance is in the public interest, there would be no need for the Commission to require a cost-benefit analysis. Without the cost-benefit analysis required by the Commission's rules, SWEPCO cannot meet its burden to show that its proposed self-insurance plan is in the public interest.[61]

Not only did Mr. Wilson's testimony not satisfy the requirements of the Commission's rules, it also overstated the target amount for the self-insurance reserve. As TIEC explained in its initial brief, Mr. Wilson's methodology of deducting the largest non-major storm from the years

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[58] SWEPCO's In. Br. at 11-12, 29-31.

[59] TIEC's In. Br. at 13-14.

[60] SWEPCO's In. Br. at 32-33.

[61] 16 T.A.C. §25.231(b)(1)(G).

in which there were cost estimates ignores the possibility that there could be multiple non-major storms.[62] Accordingly, it is not a conservative estimate as SWEPCO claims.[63] As Ms. LaConte's analysis shows, excluding the estimated amounts for 2000 and 2004 decreases the required annual accrual to $1,255,000.[64] If SWEPCO's self-insurance reserve is approved, the annual accrual should be set at this lower amount.

III. Rate of Return [PO Issues 4, 5, 8, 9]

A. Overall Rate of Return, Return on Equity, Cost of Debt [PO Issue 8]

1. Return on Equity

a. SWEPCO's risk and its required cost of capital have only declined since its last rate case.

SWEPCO's return on equity (ROE) request of 10.35%—a full 75 basis points above its currently approved ROE of 9.6%—is unreasonably high and should be rejected. Instead, SWEPCO's ROE should be set in accordance with the clear, observable evidence presented in this proceeding, which shows that SWEPCO's cost of capital and business and operating risks have only declined since its last rate case in 2017. Indeed, the only way SWEPCO is able to justify its inflated ROE request is by ignoring this evidence and misinterpreting data.

For example, SWEPCO claims that Staff and intervenors' proposed ROEs are too low because the average authorized ROE for vertically integrated utilities since 2017 has been 9.69%, citing the testimony of Walmart witness Ms. Perry.[65] But SWEPCO fails to mention that Ms. Perry's testimony also shows that there has been a clear declining trend in authorized ROEs for vertically integrated utilities during that period, from 9.80% in 2017 to 9.55% in 2020 and 9.30% in 2021 so far.[66] SWEPCO tries to justify ignoring the most recent data on the grounds that 2020

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[62] TIEC's In. Br. at 15.

[63] SWEPCO's In. Br. at 33-34.

[64] TIEC Ex. 4, LaConte Dir. at 21-22.

[65] SWEPCO's In. Br. at 44.

[66] Walmart Ex. 1, Direct Testimony of Lisa V. Perry at 11 (Perry Dir.).

was an "outlier" year, but does not explain why market conditions in 2020 meant that authorized ROEs in 2020 (or 2021) were unrepresentatively low.[67] Elsewhere in its brief, SWEPCO appears to be claiming that volatility in the debt and equity markets in 2020 justify a higher ROE for SWEPCO,[68] which is at odds with its contention that authorized ROEs were too low in 2020 because of outlier market conditions. SWEPCO also claims that these annual averages are misleading because the number of cases or jurisdictions issuing orders within a year may vary,[69] but SWEPCO cannot refute that authorized ROEs have, in fact, declined since 2017. As TIEC laid out in detail in its initial brief, even Moody's, an independent third-party source, has acknowledged that authorized ROEs have been declining, and has stated that it expects that trend to continue without issue.[70] SWEPCO's attempts to explain away the data fall flat.

SWEPCO's ROE request also flies in the face of observable market evidence that the cost of capital has declined dramatically since 2017. Interest rates have fallen across the board, as Treasury yields, corporate bond yields, and the Federal Funds rate have all dropped by over 100 basis points between the pendency of Docket No. 46449 and this proceeding.[71] SWEPCO claims that this decline in interest rates is an indicator of market volatility and that higher volatility means that SWEPCO faces more risk and requires a higher ROE than it did four years ago.[72] But SWEPCO never explains why stock market volatility requires higher ROEs for utility investments. SWEPCO acknowledges that during periods of market volatility, investors generally seek lower-yielding, less risky investments—colloquially called the "flight to safety" or the "flight to

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[67] SWEPCO's In. Br. at 45

[68] *Id.*

[69] *Id.* at 50-51.

[70] TIEC's In. Br. at 21-22 (citing TIEC Ex. 3B, Confidential Workpapers to the Direct Testimony of Michael P. Gorman at MPG Confidential WP 15 (Moody's Investors Service, *2021 Outlook Stable on Strong Regulatory Support and Robust Residential Demand* (Oct. 29, 2020)) at 5 (Gorman Conf. Workpapers)).

[71] TIEC Ex. 46.

[72] SWEPCO's In. Br. at 46. In his article comparing the predictive risk premium model (PRPM) against more traditional ROE models, Mr. D'Ascendis defined the "flight to quality" as "the willingness of an investor to accept a lower, but more certain, return during financial downturns," and used the flight to quality as the explanation for why the PRPM predicted ***lower*** required ROEs during financial downturns. SWEPCO Ex. 38A, Workpapers to the Rebuttal Testimony of Dylan W. D'Ascendis at 1176 (D'Ascendis Reb. Workpapers).

quality."[73] At the hearing, Mr. D'Ascendis recognized that the conventional wisdom is that utility stocks are a defensive investment that investors flock to during market instability, but contended that this conventional wisdom did not hold true during the most recent downturn.[74] Mr. D'Ascendis based this conclusion on the fact that utility stocks moved in tandem with the overall market in 2020,[75] but changes in stock price alone do not capture the entire picture. Utility investors not only invest in utility stocks for capital gains (i.e., changes in stock price), but also for the steady income stream that comes from dividends.[76] That is not true to the same extent for the general market.[77] Thus, simply looking at stock price movements ignores the fact that the total return for utility stocks has not declined as steeply as the overall market, as utility investors have continued to receive stable returns through dividends.[78] Indeed, for the vast majority of utility companies, those dividends have stayed stable or even grown, as in the case of AEP.[79]

Further, SWEPCO's fixation on market volatility ignores that the outlook on the overall market, and the utility industry specifically, is generally positive and expected to improve. SWEPCO makes the erroneous claim that the outlook for utilities is not stable, citing to an S&P report quoted in Mr. D'Ascendis's testimony for the proposition that utilities have performed poorly from a credit quality perspective.[80] The title of that S&P report is "North American Regulated Utilities' Negative Outlook Could See Modest Improvement," and while S&P notes that credit downgrades outpaced upgrades in 2020, it also states that it "expect[s] a modest

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[73] SWEPCO's In. Br. at 46.

[74] Tr. at 874:1-15 (D'Ascendis Cross) (May 24, 2021).

[75] *Id.* at 874:9-20.

[76] *Id.* at 874:21-875:2.

[77] *Id.* at 875:3-16 (explaining that electric utilities generally pay higher dividends than the rest of the S&P 500). For example, many companies such as technology firms often pay either no dividend, or very low dividends. *See* TIEC Ex. 49 at Bates 002-008 (showing dividend yields of 0% for many companies in the S&P 500, including Amazon, Alphabet, and Facebook).

[78] Tr. at 875:9-19 (D'Ascendis Cross) (May 24, 2021).

[79] *Id.* at 875:25-877:16 (stating that only two electric utility companies have cut dividends); TIEC Ex. 6 at Bates 010.

[80] SWEPCO's In. Br. at 45-46.

improvement to credit quality over the next 12 months."[81] Further, SWEPCO entirely fails to mention Moody's most recent assessment of the credit outlook for the utility industry, published in October 2020:

> We are maintaining a stable outlook for the US regulated utilities industry, reflecting our expectation for continued strong regulatory support, robust residential demand and a recovering economy in 2021. As a critical infrastructure sector with a regulated business model that provides good cost recovery, regulated utilities have remained relatively resilient in the face of the uncertain economic environment caused by the coronavirus pandemic.[82]

While SWEPCO claims that there is "no doubt" that the last twelve months have been characterized by extreme volatility in the debt and equity markets,[83] the truth is that utilities have been able to maintain extremely robust access to low-cost capital, to the point where they have increased their debt levels to take advantage of historically low interest rates, as Moody's has reported:

> We expect the sector to continue to have strong access to capital markets, as was exhibited during the turbulent capital market environment in March in the wake of the initial coronavirus outbreak in the US. Debt balances have been higher than normal in 2020, as some utilities hold more cash for liquidity and many have opportunistically refinanced upcoming maturities and issued incremental debt to take advantage of low interest rates.[84]

Similarly, the same S&P report cited by SWEPCO states that the electric utility industry "generally performed well during the pandemic" and that it "generally had consistent access to the capital markets."[85] Thus, the evidence is clear that utilities were generally able to weather the market

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[81] SWEPCO Ex. 38A, D'Ascendis Reb. Workpapers at 22.

[82] TIEC Ex. 3, Direct Testimony and Exhibits of Michael P. Gorman at 20 (quoting Moody's Investors Service, *2021 Outlook Stable on Strong Regulatory Support and Robust Residential Demand* (Oct. 29, 2020)) (Gorman Dir.).

[83] SWEPCO's In. Br. at 45.

[84] TIEC Ex. 3B, Gorman Conf. Workpapers at MPG Confidential WP 15 (Moody's Investors Service, *2021 Outlook Stable on Strong Regulatory Support and Robust Residential Demand* (Oct. 29, 2020)) at 3.

[85] TIEC Ex. 3, Gorman Dir. at 19-20 (citing S&P Global Ratings, *North American Regulated Utilities' Negative Outlook Could See Modest Improvement* (Jan. 20, 2021)).

turmoil caused by the pandemic and that conditions are only expected to continue to improve going forward.[86]

In addition to the current low cost-of-capital environment and improving economic conditions, the evidence also shows that SWEPCO itself faces less business and operational risk than it did during its prior rate case. While SWEPCO claims that no party has explained why SWEPCO is less risky today than it was four years ago,[87] it has seemingly forgotten that the Texas Legislature in 2019 enacted the GCRR statute, which allows SWEPCO to recover its generation capital investment on the day of commercial operation, significantly reducing regulatory lag for SWEPCO's generation investments.[88] Indeed, Moody's has specifically cited the GCRR statute as a mechanism that would allow for lower allowed ROEs.[89]

In sum, SWEPCO's claims of higher market volatility and higher risk are unsupported by the evidence and do not justify increasing its authorized ROE. Rather, SWEPCO's ROE should be adjusted downward to reflect the decline in the cost of capital and the improvement in its business and operating risk that have occurred since its ROE was last set at 9.6%. As set out in detail below, Mr. Gorman's recommended ROE of 9.15% would fairly compensate SWEPCO's shareholders while maintaining reasonable rates for its ratepayers.

b. Mr. Gorman's ROE results are reasonable.

i. Mr. Gorman's discounted cash flow (DCF) model results are reasonable.

While SWEPCO accepts Mr. Gorman's constant-growth DCF model, SWEPCO offers several erroneous arguments against Mr. Gorman's multi-stage and sustainable-growth DCF models.[90] First, SWEPCO claims that Mr. Gorman's use of the multi-stage DCF model is not

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[86] *Id.* at 19-21.

[87] SWEPCO's In. Br. at 44.

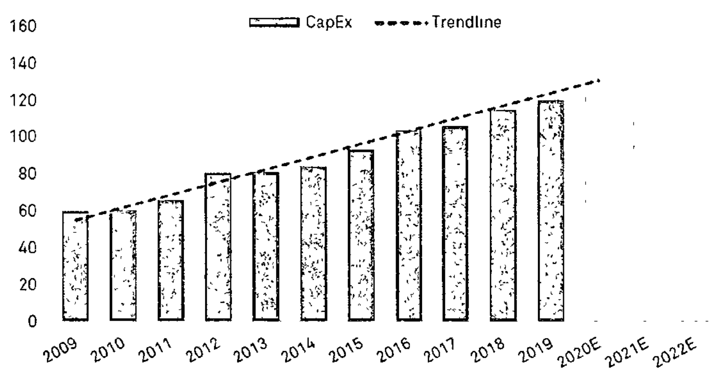
[88] Tr. at 1070:16-23 (D'Ascendıs Cross) (May 14, 2021); PURA § 36.213.

[89] TIEC Ex. 3B, Gorman Conf. Workpapers at MPG Confidential WP 15 at 5.

[90] SWEPCO's In. Br. at 51.

appropriate for utility companies because they are in a mature, "steady-state" stage.[91] While utilities may not have the explosive growth of less mature industries, they do experience periods of relatively higher growth.[92] As Mr. Gorman explained, when utilities undertake large capital expenditure programs, their rate base grows rapidly, which accelerates earnings growth.[93] Once a major construction cycle levels off, rate base growth slows, and earnings growth also drops to a lower sustainable rate.[94] Currently, utilities are in a period of high capital investment that is expected to taper off, as shown in the following chart taken from a report published by S&P:[95]

Energy utility actual and estimated capital expenditures ($B)



Compiled Oct. 27, 2020.
Source: S&P Global Market Intelligence

Thus, the current average projected growth rate of 5.46% is not expected to be sustained over the long term.[96] Indeed, academic research and empirical data has demonstrated that the growth rate of a utility cannot, over the long run, exceed the long-term gross domestic product (GDP) growth rate of the economy in which it sells goods and services,[97] which is currently projected to be

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[91] *Id.*

[92] TIEC Ex. 3, Gorman Dir. at 33.

[93] *Id.*

[94] *Id*

[95] TIEC Ex. 3B, Gorman Conf. Workpapers at MPG Confidential WP 8 (RRA Financial Focus, Utility Capital Expenditures Update) at 1.

[96] TIEC Ex. 3, Gorman Dir. at 33-34.

[97] *Id.* at 35-37.

4.35%.[98] For example, in the "Fundamentals of Financial Management," the authors state that "dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)."[99] Similarly, the historical growth of the U.S. stock market from 1926 to 2019 was 6.1%, and the growth of U.S. GDP was 6.0% over that same period.[100] The multi-stage DCF model, unlike the constant-growth DCF model, recognizes that current analyst growth rates are not sustainable in perpetuity.[101] That utilities are a relatively mature industry experiencing only modestly high growth is captured by the limited difference between the short-term and long-term growth rates used by Mr. Gorman in his multi-stage DCF analysis. Accordingly, Mr. Gorman's multi-stage DCF produces a reasonable estimate of SWEPCO's required ROE.

The sustainable growth methodology similarly takes into account the fact that earnings growth projections from sources such as Value Line and Bloomberg are explicitly stated as three- to five-year growth rates and thus may not reflect growth rates that are sustainable in perpetuity, as required by the constant-growth DCF model.[102] Because utilities use retained earnings to fund rate base growth and thus earnings growth, the sustainable growth methodology uses the long-term earnings retention ratio to assess whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.[103] Thus, Mr. D'Ascendis's analysis showing that there is a negative correlation between analysts' five-year growth rates and earnings retention ratios misses the point.[104] The long-term earnings retention ratio is intended to show whether those analysts' five-year growth rates are sustainable indefinitely, so it should be expected that there is no correlation between the two. Mr. Gorman's sustainable growth methodology

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[98] *Id.* at Ex. MPG-10.

[99] *Id.* at 35.

[100] *Id.* at 36.

[101] *Id.* at 32-33.

[102] *Id.* at 31-32; *see also* Tr. at 896:5-898:15 (D'Ascendis Cross) (May 24, 2021).

[103] TIEC Ex. 3, Gorman Dir. at 31-32.

[104] SWEPCO's In. Br. at 51; see also SWEPCO Ex. 38, Rebuttal Testimony of Dylan W. D'Ascendis at 58-59 (D'Ascendis Reb.).

showed that based on long-term earnings retention ratios, the long-term sustainable growth rate for the proxy group is 4.50%, similar to the current long-term GDP growth projection of 4.35%.[105] Accordingly, both the sustainable growth methodology and current GDP growth estimates provide data points showing that the constant-growth DCF based on a three- to five-year average growth rate of 5.46% is overestimating the required ROE because that growth rate cannot be sustained in perpetuity.[106] Thus, it was appropriate for Mr. Gorman to factor the sustainable growth and multi-stage DCF models into his DCF analysis, and his overall DCF estimate of 8.90% is reasonable.[107]

ii. Mr. Gorman's Risk Premium Analysis is Reasonable.

SWEPCO's primary criticism of Mr. Gorman's Risk Premium model is to repeat the faulty claim that equity risk premiums have an inverse relationship with interest rates.[108] However, as Mr. Gorman testified, there is not a simplistic inverse relationship between equity risk premiums and interest rates as Mr. D'Ascendis suggests.[109] Such an assumption ignores that there are other market factors that affect differences in investment risk between stock and bond investments. While there are academic studies showing that there is an inverse correlation between equity risk premiums and interest rates, researchers have found that this relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[110] In other words, Mr. D'Ascendis is confusing correlation with causation, and while there may be a correlation between equity risk premiums and interest rates, what is truly relevant is the market's perception of relative risk differential between bond and equity investments.

Mr. Gorman analyzed the market's perception of the difference in investment risk between stock and bond investments by comparing current and historical spreads between Treasury yields

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[105] TIEC Ex. 3, Gorman Dır. at 32, 37.

[106] *Id.* at 30-32.

[107] *Id.* at 40.

[108] SWEPCO's In. Br. at 51.

[109] TIEC Ex. 3, Gorman Dir. at 68.

[110] *Id.* at 68-69.

and utility and corporate bond yields.[111] This analysis showed that investors are currently expecting relatively higher returns for higher-risk investments, suggesting that the equity risk premium should be higher than the historical average.[112] As a result, Mr. Gorman used solely the upper end of his historical ranges.[113] For instance, while the average indicated equity risk premium above Treasury yields was 5.65%, Mr. Gorman used an equity risk premium of 7.02%.[114] Mr. Gorman's analysis thus takes into account the observable market evidence showing that equity risk premiums are currently higher than their historical average, effectively accounting for the impact of what SWEPCO claims is a simplistic inverse relationship.

SWEPCO also criticizes Mr. Gorman's use of the period from 1986 through 2019 to calculate the average historical equity risk premium. However, Mr. D'Ascendis's own analysis of the equity risk premium using prior authorized ROE decisions only went back to 1980, and he did not provide any explanation why he chose that year as a cutoff date.[115]

Regardless, the two criticisms leveled by SWEPCO do little to change the actual analysis. SWEPCO asserts that correcting Mr. Gorman's analysis results in indicated ROEs of 9.44% and 9.57%,[116] but Mr. D'Ascendis's adjustments actually resulted in lower equity risk premiums than what Mr. Gorman used. Mr. Gorman's equity risk premiums above Treasury bonds and corporate bonds were 7.02% and 5.77%, respectively.[117] On the other hand, Mr. D'Ascendis's adjustments resulted in equity risk premiums of 6.96% and 5.53%.[118] The actual reason why Mr. D'Ascendis's

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[111] *Id* at 43-46.

[112] *Id.* at 45-46.

[113] *Id.* at 46-47.

[114] *Id.* at 46-47, Ex. MPG-12.

[115] SWEPCO Ex. 8, Direct Testimony of Dylan W. D'Ascendis Dir. at 39 (D'Ascendis Dir.); *see also* SWEPCO Ex. 38, D'Ascendis Reb. at 64-67 (criticizing Mr. Gorman's use of 1986-2019 but not providing an alternative time period nor explaining why his use of 1980-2019 was appropriate).

[116] SWEPCO's In. Br. at 51.

[117] TIEC Ex. 3, Gorman Dir. at 46-47.

[118] SWEPCO Ex. 38, D'Ascendis Reb. at 70. Mr. D'Ascendis used a projected Treasury yield of 2.48%, which indicated an ROE of 9.44%, meaning the equity risk premium was 9.44%-2.48% = 6.96%. He also used a

purported adjustments resulted in higher ROEs was his use of long-term projected interest rates.[119] But as set forth in detail in TIEC's initial brief, interest rate projections are notoriously inaccurate.[120] Accordingly, current interest rates and short-term projections, as Mr. Gorman used, are a more accurate indicator of interest rates expected to prevail in the future than long-term projections.[121] Mr. Gorman's Risk Premium result of 9.20% is reasonable and should be factored into setting SWEPCO's ROE.[122]

iii. Mr. Gorman's CAPM analysis is reasonable.

In criticizing Mr. Gorman's CAPM analysis, SWEPCO faults Mr. Gorman for not using long-term interest rate forecasts from Blue Chip despite his use of other forecasts from Blue Chip.[123] But as discussed above, both Mr. Woolridge and Mr. Gorman testified that long-term interest rate projections are known to be extremely inaccurate.[124] In fact, other regulatory commissions have also concluded that the use of projected interest rates inflates ROE results.[125] While Mr. Gorman used projected GDP growth rates from Blue Chip,[126] SWEPCO has not presented any evidence demonstrating that GDP forecasts are generally inaccurate. Moreover, Mr. Gorman corroborated the GDP forecasts from Blue Chip with several other sources, including the Energy Information Administration, the Congressional Budget Office, Moody's Analytics, the Social Security Administration, and the Economist Intelligence Unit, all of which were similar to

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projected utility bond yield of 4.04%, which indicated an ROE of 9.57%, meaning the equity risk premium was 9.57%-4.04% = 5.53%.

[119] *Id.* at 70.

[120] TIEC's In. Br. at 37; see also Tr. at 1005:12-1006:4 (Woolridge Recross) (May 24, 2021); CARD Ex. 4, Direct Testimony of Randall Woolridge Dir. at 43 (Woolridge Dir.).

[121] Tr. at 1026:24-1027:15 (Gorman Cross) (May 24, 2021).

[122] TIEC Ex. 3, Gorman Dir. at 47.

[123] SWEPCO's In. Br. at 51-52.

[124] Tr. at 1005:12-1006:4 (Woolridge Recross) (May 24, 2021); Tr. at 1026:24-1027:15 (Gorman Cross) (May 24, 2021).

[125] *See, e.g.*, TIEC Ex. 54 at Bates 006.

[126] Tr. at 1023:9-15 (Gorman Cross) (May 24, 2021).

(though lower than) Blue Chip's forecast.[127]

SWEPCO also claims that Mr. Gorman's CAPM analysis is flawed because he relied on a historical market return to calculate the market risk premium. However, the evidence shows that the historical market returns Mr. Gorman used are actually higher than current projections of the total market return. Mr. Gorman calculated expected market returns of 11.29% and 12.1%.[128] Mr. D'Ascendis used Value Line's projection of the growth of the overall market over the next three- to five-year period in his models, and it shows an expected market return of 8.47%.[129] Thus, Mr. Gorman's expected market return is in fact conservative relative to what current investor sentiment and market conditions would suggest. The only way Mr. D'Ascendis was able to estimate an expected market return significantly higher than what Value Line projects was by running a flawed DCF analysis on the S&P 500, as TIEC laid out in its initial brief.[130] Mr. Gorman's CAPM analysis is based on sound assumptions that reflect current market conditions, and it produced a reasonable estimate of SWEPCO's required ROE of 9.5%.[131]

c. Mr. D'Ascendis's ROE analyses are inflated and unreliable, and should be rejected.

TIEC detailed all of the myriad issues with Mr. D'Ascendis's ROE analyses in its initial brief, and those arguments will not be repeated here. As recognized by multiple regulatory commissions across the country, Mr. D'Ascendis's analyses are based on flawed methodologies and biased inputs that serve only to inflate his results.[132] Further, Mr. D'Ascendis's small-size and credit-risk adders to his ROE results completely ignore the reality of SWEPCO's low business risk as an operating subsidiary of AEP and are unjustified.[133] SWEPCO's request for an ROE of

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[127] TIEC Ex. 3, Gorman Dir. at 38-39.

[128] *Id.* at 50-51.

[129] Tr. at 893:9-19 (D'Ascendis Cross); SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 32.

[130] TIEC's In. Br. at 35-36.

[131] TIEC Ex. 3, Gorman Dir. at 53.

[132] TIEC's In. Br. at 32-40.

[133] *Id.* at 40-42.

10.35% should be denied, and the Commission should set an ROE for SWEPCO in line with Mr. Gorman's recommended ROE of 9.15%.

IV. Expenses [PO Issues 1, 14, 24, 29, 30, 32, 33, 40, 41, 42, 44, 45, 46, 49, 72, 73, 74]

A. Transmission and Distribution O&M Expenses [PO Issue 14, 24]

3. Proposed Deferral of SPP Wholesale Transmission Costs [PO Issues 72, 73, 74]

As explained in the initial briefs of TIEC,[134] Staff,[135] and East Texas Saltwater Disposal Company (ETSWD),[136] SWEPCO's unprecedented proposal to defer its Southwest Power Pool (SPP) approved transmission charges (ATC) for dollar-for-dollar recovery should be rejected. SWEPCO's brief does not offer any justifications that would warrant this extraordinary relief.

SWEPCO cites to prior findings of the Commission, apparently for the proposition that net ATC costs are reasonable costs.[137] But that does not mean that an unprecedented tracker must (or should) be imposed to recover those costs. Texas is a historical test-year state, and the Commission's cost-of-service rule calls for rates to be set based on the reasonable and necessary expenses that the utility incurred during the test year.[138] Indeed, that is how the Commission has allowed utilities like SWEPCO to recover their net ATC for many years, as both base rates and transmission cost recovery factor (TCRF) rates are set based on historical test years.[139]

SWEPCO's implication that its tracker should be approved because ATC are generally recoverable costs also runs afoul of recent Commission precedent. In Docket No. 46449,

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[134] TIEC's In. Br. at 44-46.

[135] Staff's In. Br. at 49-50.

[136] ETSWD's In. Br. at 10.

[137] SWEPCO's In. Br. at 62.

[138] 16 T.A.C. § 25.231(a)-(b).

[139] *Id.*; 16 T.A.C. § 25.239; *see also Application of Southwestern Electric Power Company for Approval of a Transmission Cost Recovery Factor*, Docket No. 42448, Final Order at FoFs 32-45 & CoL 8 (Nov. 24, 2014).

SWEPCO proposed to defer SPP Z2 expenses, but the Commission denied the request.[140] Specifically, the Commission found that such deferred accounting treatment is an extraordinary remedy only warranted under special circumstances, such as to preserve financial integrity.[141] Notably, SWEPCO has not demonstrated that its ATC tracker mechanism is justified by any such circumstances here, particularly given that the SWEPCO's SPP open access transmission tariff (OATT) revenues have actually increased more than SWEPCO's SPP OATT charges since SWEPCO's last rate case and its last TCRF proceeding.[142]

SWEPCO's reliance on the ERCOT TCRF rule is equally unavailing.[143] As explained in TIEC's initial brief, the ERCOT TCRF rule is based on a different statute,[144] and the ERCOT rule specifically implements a tracking mechanism.[145] The non-ERCOT TCRF rule does not authorize a tracker.[146] To the contrary, the Commission has interpreted this rule as requiring that rates be set based on a historical test year without adjustments.[147] SWEPCO claims that its proposed new mechanism would merely "complement" the non-ERCOT TCRF rule, but in actuality it would constitute an ad hoc amendment to that rule.[148]

SWEPCO also stresses that its proposal is to track the net SPP OATT bill, not just the SPP

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[140] Docket No. 46449, PFD at 276-79, *adopted by* Order on Rehearing at FoFs 238-44.

[141] *Id.* at 278-79.

[142] TIEC Ex. 1, Pollock Dir. at 11.

[143] SWEPCO's In. Br. at 63.

[144] *Rulemaking Proceeding to Amend PUC Subst R. 25.193 Relating to Distribution Service Provider Transmission Recovery Factor (TCRF)*, Proj. No. 37909, Order Adopting Amendments to § 25.193 as Approved at the September 29, 2010 Open Meeting at 33-35 (Oct. 4, 2010) (explaining that the amendment was adopted under PURA § 35.004(d)). Moreover, PURA § 35.004(d) specifically states that its provisions are notwithstanding PURA § 36.201, which prohibits automatic cost adjustments. The non-ERCOT TCRF statute contains no such language. PURA § 36.209.

[145] 16 T.A.C. § 25.193(b)(2)(B).

[146] *See generally* 16 T.A.C. § 25.239.

[147] Docket No. 42448, Final Order at CoL 8.

[148] SWEPCO's In. Br. at 64. In essence, SWEPCO's proposal would add to the non-ERCOT TCRF rule the language contained in the ERCOT TCRF rule that provides for the tracker. 16 T.A.C. § 25.193(b)(2)(B).

costs it is billed.[149] While SWEPCO's proposal has been less than clear,[150] TIEC notes that its opposition to SWEPCO's proposed mechanism is not premised on it applying to costs only. A utility's actual costs and revenues are constantly changing compared to test year levels.[151] Singling out one cost-component, net ATC costs, for dollar-for-dollar recovery would constitute improper piecemeal ratemaking that is not justified by any statute or rule. Further, SWEPCO has not demonstrated that its proposed mechanism is necessary for it to have a reasonable opportunity to earn a reasonable return. SWEPCO's proposal should be rejected.

6. Allocated Transmission Expenses Related to Retail Behind-the-Meter Generation

Most of SWEPCO's brief on this point is simply a verbatim recitation of the pre-filed rebuttal testimony of SWEPCO's two witnesses on this issue, Charles Locke, and Richard Ross, as if the hearing on this issue never happened. SWEPCO continues to assert that it was just following orders from SPP, notwithstanding SWEPCO's inability to point to any such order and SPP's insistence that it has no authority to verify or compel SWEPCO to report its Network Load in any particular manner.[152] SWEPCO completely ignores the fact that Mr. Locke's new interpretation of Section 34.4 makes no sense as a matter of logic or grammar, perhaps because SWEPCO has made exactly that point in recent submissions to SPP.[153]

SWEPCO asserts that the dispute on this issue is not with it but with SPP[154] and it turned to an SPP employee to defend it—Charles Locke, the primary proponent of the new interpretation

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[149] SWEPCO's In. Br. at 62.

[150] For instance, Mr. Aaron referred in direct testimony to the tracker as deferring "ongoing SPP charges" and "ATC," though his Exhibit JOA-5 included SPP revenue credits under "Investment Related Expenses" and only SPP charges were included under "ATC." SWEPCO Ex. 31, Direct Testimony of John O. Aaron at 29-31 & Ex. JOA-5 (Aaron Dir.).

[151] For example, when a utility experiences load growth over test-year levels, this increases the utility's revenues. However, the Commission has decided that the non-ERCOT TCRF rule does not provide for a load-growth adjustment. *Application of Entergy Texas, Inc. to Set a Transmission Cost Recovery Factor*, Docket No. 49057, Order on Rehearing at 1-3 (Oct. 2, 2019).

[152] Tr. at 771:15-772:25 (Locke Cross) (May 21, 2021).

[153] TIEC Ex. 36B.

[154] SWEPCO's In. Br. at 72.

of this decades-old provision. But SWEPCO's brief ignores the fact that Mr. Locke demonstrated a woeful lack of knowledge about the terms of the SPP tariff, the history of SPP's prior interpretations, and FERC's prior interpretation of identical tariff language for the Midcontinent Independent System Operator (MISO).[155] SWEPCO's recent experiment with Mr. Locke's novel and unprecedented interpretation of this longstanding provision should be put to an end in this case.

a. SWEPCO's request to shift $5.7 million from Arkansas and Louisiana to Texas is a jurisdictional allocation issue.

While SWEPCO characterizes this issue as one involving a disallowance of $5.7 million in transmission expenses,[156] it became clear at the hearing that the issue is actually about the artificial addition of a single Texas customer with behind-the-meter generation (BTMG) to SWEPCO's jurisdictional allocation study. SWEPCO's rate filing in this case barely mentioned the treatment of load self-supplied by retail customers, and SWEPCO did not break out the amount SWEPCO claims to have paid in additional charges to SPP as a result of including Eastman Chemical Company's (Eastman) self-served load.[157] When asked in discovery what the impact of including retail BTMG in monthly peak load was, SWEPCO stated that the impact was a $5.7 million increase in its revenue requirement.[158] But it became clear at the hearing that this $5.7 million amount had no relation to whatever additional amount SWEPCO may have paid SPP as a result of SWEPCO's decision to include the self-served load of a single Texas customer in its calculation of its Monthly Network Load. SWEPCO has not identified that amount, and it is not in the record. Rather, the $5.7 million SWEPCO identified is the revenue impact in the jurisdictional allocation study of adding that single customer's self-served load in Texas to the Texas jurisdictional allocators, while completely ignoring all retail self-served load in Arkansas

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[155] Tr. at 830:21-831:25, 837:12-847:23 (Locke Cross) (May 21, 2021).

[156] SWEPCO's In. Br. at 72.

[157] SWEPCO Ex. 31, Aaron Dir. at Ex. JOA-5 (showing only total SPP charges, not charges associated with adding Eastman's load to Monthly Network Load).

[158] TIEC Ex. 76.

and Louisiana.[159]

The impact of including Eastman in the jurisdictional allocation study was shown in SWEPCO's response to TIEC's RFI 11-1.[160] The relevant part is shown below:

Jurisdiction		TOTAL COMPANY	AT ISSUE TEXAS	ARKANSAS	LOUISIANA	FERC
with Eastman	REVENUE DEFICIENCY / (SURPLUS)	228,419,735	105,026,238	88,619,584	43,013,790	(8,239,877)
without Eastman	REVENUE DEFICIENCY / (SURPLUS)	228,419,735	99,339,170	90,652,000	46,668,442	(8,239,877)
		-	5,687,068	(2,032,415)	(3,654,652)	-

As can be seen, SWEPCO's approach to calculating the $5,687,068 it asserted was attributable to including Eastman's self-served load does not actually reflect any change to SWEPCO's total company revenue requirement. Under both the "with Eastman" and "without Eastman" lines, the total company revenue deficiency is the same—$228,419,735. As SWEPCO has presented the issue in this case, the inclusion or exclusion of Eastman's load has no impact whatsoever on SWEPCO's total company revenue requirement. Rather, it affects only what SWEPCO witness John Aaron referenced as the "zero-sum game" of allocating the total company revenue requirement between the jurisdictions.[161] Adding a retail customer's self-served load to the transmission allocator in Texas while ignoring similar load in other states had the effect of reallocating $5.7 million of the total company revenue requirement from Arkansas and Louisiana to Texas.[162] It is this erroneous increase to the Texas jurisdictional allocator that is at issue in this case.

SWEPCO's justification for shifting costs from Arkansas and Louisiana to Texas is that its decision to include Eastman's self-served load in its reporting of Monthly Network Load increased SWEPCO's SPP charges.[163] But adding Eastman's self-served load to the Texas transmission allocator shifted costs to Texas that have nothing to do with SPP charges, including the return on

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[159] Tr. at 1212:8-1213:4 (Aaron Cross) (May 25, 2021).

[160] TIEC Ex. 74.

[161] Tr. at 1212:4-7 (Aaron Cross) (May 25, 2021).

[162] *Id* at 1211:11-1212:7, 1213:4-8.

[163] TIEC Ex. 2, Supplemental Testimony of Jeffry C. Pollock at Ex. JP-S1 (Pollock Supp. Dir.).

SWEPCO's own transmission invested capital, SWEPCO's investment-related expenses, and SWEPCO's transmission-related O&M expenses.[164] Because of the complete absence of any explanation in SWEPCO's filing of the actual amount of claimed additional SPP costs attributable to including Eastman in Monthly Network Load, combined with the way SWEPCO avoided discovery requests asking for the impact of including Eastman's load,[165] there is nothing in the record that reflects the amount of any actual Test Year increase in SPP payments attributable to SWEPCO's decision to include Eastman's self-served load in Monthly Network Load. It is certainly not the $5,687,068 that SWEPCO shifted to Texas in the jurisdictional allocation study.

Because SWEPCO increased its Texas rate request by inflating the Texas jurisdictional allocator for transmission costs, the BTMG issue in this case is not actually a disallowance issue, it is simply an issue of the allocation of SWEPCO's total costs between SWEPCO's three retail jurisdictions. To the extent that SWEPCO included additional SPP costs in SWEPCO's total company costs by reporting Eastman's self-served load, that amount is unknown. But what is known is that SWEPCO proposes to reduce the Arkansas and Louisiana jurisdictional allocations in this case by a total of $5.7 million—even though it did not reduce the costs allocated to those jurisdictions in its recent rate cases in those states.[166] And it seeks to shift those Arkansas and Louisiana costs to Texas ratepayers.

Because this is an issue of the jurisdictional allocation of SWEPCO's total transmission costs, SWEPCO's argument that the PUC lacks jurisdiction to disallow any SPP expense is completely inapposite. It is well-established that state commissions have jurisdiction to adopt jurisdictional allocation methodologies in allocating a utility's costs. That is true even when different states adopt different allocation methodologies that result in recovery of less than the total company costs. That is a risk that a utility assumes when it chooses to operate in multiple

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[164] *Id.* at 2.

[165] TIEC Ex. 76

[166] Tr. at 1197:7-17 (Aaron Cross) (May 25, 2021).

jurisdictions.[167]

Rejecting SPP's addition of Eastman's self-served load to the Texas jurisdictional allocator does not require a reduction to SWEPCO's total company revenue requirement or the disallowance of any expense. It is simply a rejection of SWEPCO's new proposal to add the phantom load of a single Texas customer to its jurisdictional allocators, and the adoption instead of the jurisdictional allocation methodology that SWEPCO has used not only in its recent cases in Arkansas and Louisiana, but in all its other Texas cases.[168] That is well within the Commission's discretion.[169] In fact, in this case, the only way to apply consistent jurisdictional methodologies in all three retail jurisdictions would be to reject SWEPCO's new proposal and to adopt the jurisdictional allocation methodology SWEPCO has used in both other retail jurisdictions.

As set forth below, SWEPCO's rationale for this shift of costs to Texas—that it was following an alleged directive from SPP to include retail self-served load in Network Load—is misguided. In the first place, that would not be a justification for changing how SWEPCO and the PUC have always allocated SWEPCO's ***non-SPP*** transmission costs. Yet that is what SWEPCO has proposed.[170]

Further even if the self-served load of SWEPCO's retail customers was required to be included in SWEPCO's Monthly Network Load as Mr. Locke urged, there is no argument whatsoever that the SPP OATT requires the selective inclusion of a single one of the hundreds of customers who generate a portion of their own load. Indeed, SPP's Charles Locke opined that ***all*** retail load served by self-generation must be included, and that would include SWEPCO's self-generating customers in Arkansas and Louisiana.[171] So the $5.7 million does not remotely reflect

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[167] *Entergy Texas, Inc. v. Nelson*, 889 F.3d 205, 209-10 (5th Cir. 2018) (citation omitted). In this case, however, there is no trapped cost issue, as TIEC seeks the adoption of the same methodology used in SWEPCO's other jurisdictions.

[168] Tr. at 1197:7-17 (Aaron Cross) (May 25, 2021).

[169] *See, e.g.*, *Entergy Texas, Inc.*, 889 F.3d at 209-10, 212.

[170] TIEC Ex. 1, Pollock Dir. at 25; TIEC Ex. 2, Pollock Supp. Dir. at 1-2.

[171] Tr. at 817:2-22 (Locke Cross) (May 21, 2021).

accepting SPP's alleged interpretation of the OATT. Rather, SWEPCO cherry-picks a single customer in the jurisdiction in which it is seeking a rate increase, thereby increasing that jurisdiction's allocation of costs. SWEPCO has provided no evidence of what the jurisdictional allocators would have been had SWEPCO actually applied Mr. Locke's interpretation and included self-served load in Arkansas and Louisiana in its jurisdictional allocation of transmission costs.

SWEPCO's request to adopt a new jurisdictional cost allocation methodology and shift $5.7 million in total company transmission costs from Arkansas and Louisiana to Texas should be denied.

b. SWEPCO's actions cannot be justified based on alleged "directives" from SPP.

SWEPCO continues to assert that it was simply following directives from SPP, despite its inability to produce any such directives.[172] When asked specifically to provide all instances in which it was instructed to include retail BTMG load in Network Load, SWEPCO was unable to produce a single such document.[173] While at least one SPP employee undoubtedly told SWEPCO his view, nowhere is there any official interpretation of the provision at issue. And it is apparent that other SPP employees took a different view of this same provision.[174] To the extent that Mr. Locke gave his view on the definition of Network Load to SWEPCO, that bore no resemblance to SWEPCO's approach in this case of increasing a jurisdiction's allocated costs by singling out a single customer in that jurisdiction (out of hundreds of customers with load served by BTMG) for

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[172] SWEPCO's In. Br. at 71.

[173] TIEC Ex. 66; TIEC Ex. 67.

[174] TIEC's In. Br. at 51-53; Tr. at 841:12-847:2 (Locke Cross) (May 21, 2021). SWEPCO's brief on SPP's prior interpretation of its tariff and Revision Request (RR) 241 simply recites Mr. Locke's initial testimony and ignores the fact that he blatantly mischaracterized RR 241. That proposed amendment to the definition of Monthly Network Load did not provide an exclusion of small BTMG load. That load would continue to be governed by the existing terms, which did not include it in Monthly Network Load. In order to begin including larger self-served load, however, a specific revision to section 34.4 was required, making clear that SPP's view at the time was that the definition of Monthly Network Load did not include retail self-served load. Only after this revision request was rejected did Mr. Locke begin ignoring the plain terms of Section 34.4 and asserting that it already included self-served load. *See* TIEC's In. Br. at 51-53.

this new treatment.[175]

SWEPCO tries to justify the singling out of Eastman by asserting that it excluded customers that were not synchronous.[176] But as Mr. Locke acknowledged, all the load of any actual SWEPCO customer must be synchronous.[177] Otherwise, the customer would be off the grid.[178] And generation that is asynchronous simply means that it is behind an inverter, like most solar power. Whether generation is synchronous or asynchronous has no significance for the operations of SWEPCO when the generation goes down, nor has SWEPCO offered any rational explanation for why asynchronous generation serving synchronous load would be treated differently than Eastman's load. There is certainly nothing in Section 34.4 that would make such a distinction. SWEPCO is grasping at straws in attempting to justify its discriminatory treatment of both Eastman and the State of Texas.

a. FERC precedent establishes that retail self-served load is not to be included in Monthly Network Load.

In the one case where FERC directly considered whether the definition of Monthly Network Load included self-served retail load, FERC concluded that it did not.[179] SWEPCO first attempts to distinguish that case on the grounds that it considered the self-served load of qualifying facilities (QF).[180] But that distinction is utterly unavailing for two reasons. First, the only facility to which SWEPCO chose to apply its new interpretation was a QF, so the MISO decision is directly on point. Second, the tariff language at issue in the MISO case, which is identical to the language in the SPP tariff, makes no distinction whatsoever between self-served QF load and load served by rooftop solar or other BTMG. If the terms of the tariff do not include self-served QF load, as

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[175] Tr. at 1210:6-1213:3 (Aaron Cross) (May 25, 2021).

[176] SWEPCO's In. Br. at 78.

[177] Tr. at 813:22-24, 816:16-20 (Locke Cross) (May 21, 2021); TIEC Ex. 2, Pollock Supp. Dir. at 3.

[178] TIEC Ex. 2, Pollock Supp. Dir. at 3.

[179] *Occidental Chem. Corp. v. Midwest Independent System Operator, Inc.*, 155 FERC ¶ 61,068 (2016) at ¶ 76.

[180] SWEPCO's In. Br. at 76.

FERC decided, they do not include other self-served load either.

SWEPCO next attempts to distinguish FERC's decision in the MISO case by pointing out that it related to MISO's tariff, not SPP's tariff.[181] But SWEPCO fails to acknowledge that the MISO tariff definition of Monthly Network Load is identical in every relevant respect to the SPP tariff definition.[182] The same words cannot mean one thing for MISO and the opposite for SPP.

SWEPCO also points to cases in which FERC has made even more explicit the policy that load served by retail BTMG is not to be included in Monthly Network Load.[183] But those cases simply confirm FERC's policy of not including load served by retail BTMG. The PJM decision referenced by SWEPCO was decided over ten years before FERC's decision in the MISO case that made clear that the existing language in the FERC OATT did not include self-served retail load.[184] And it simply added additional language to make even clearer that the novel application proposed by Mr. Locke would not apply. FERC has also approved more explicit language rejecting Mr. Locke's interpretation for two other ISOs.[185] These cases confirm FERC's policy of not including self-served retail load in Monthly Network Load, and the 2016 MISO decision resolved any possible ambiguity about whether the standard language in the MISO and SPP tariffs provided for the inclusion of such load.

SWEPCO's reliance on the fact that FERC has concluded that load served by the self-generation of electric utilities and cooperative customers is part of Network Load is similarly misplaced.[186] In the first place, the utilities, and cooperatives that sought an exemption for wholesale load actually cited to the fact that retail BTMG load was not included in Network Load

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[181] *Id.*

[182] TIEC Ex. 1A, Workpapers to the Direct Testimony of Jeffry C. Pollock at 835 (Pollock Dir. Workpapers); TIEC Ex. 1, Pollock Dir. at 20; *Compare* TIEC Ex. 1A, Pollock Dir. Workpapers at Bates 835 *with* TIEC Ex. 42.

[183] SWEPCO's In. Br. at 76.

[184] *Id.*; *see PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113 (2004).

[185] Eastman Ex. 1, Direct Testimony and Exhibits of Ali Al-Jabir at 23-24 (Al-Jabir Dir.).

[186] SWEPCO's In. Br. at 74-75.

in support of their argument that wholesale load should be treated the same.[187] Second, electric utilities and cooperatives, unlike retail customers, are actually "Network Customers" within the meaning of the term in the FERC OATT,[188] so the language relating to "Network Customer's Monthly Network Load" would actually apply to a utility's self-served load, but not to a retail customer who was supplying its own service. Finally, FERC noted that electric utilities and cooperatives could avoid having their load included in Network Load by obtaining alternate transmission service, an option unavailable to retail customers.[189]

The applicable FERC precedent makes clear that a retail customer's self-served load is not included in "Network Customer's Monthly Network Load," and Mr. Locke's interpretation to the contrary simply ignores this clear precedent.

b. The Texas PUC has jurisdiction to (1) reject SWEPCO's proposal shift of costs to Texas ratepayers and (2) reject SWEPCO's new interpretation of Monthly Network Load.

SWEPCO argues that the Texas Commission lacks jurisdiction to disallow any payments SWEPCO makes to SPP, whether they were lawful charges under the tariff or not. That argument is wrong, as discussed below. But it is also irrelevant in this case because of the peculiar way in which SWEPCO has proposed to add \$5.7 million to the cost of Texas ratepayers. As shown in section IV.A.6.a, rejecting SWEPCO's proposed jurisdictional shift does not require the disallowance of any costs included in SWEPCO's proposed revenue requirement. There is nothing in the record that even shows the amount of additional costs SWEPCO paid to SPP by reason of including Eastman's self-served load in Monthly Network Load. Instead, SWEPCO calculated the \$5.7 million shift by using SWEPCO's actual load for Louisiana and Arkansas, while adding a single customer's self-served load to the Texas actual load.[190] SWEPCO then used the resulting jurisdictional allocation percentages to allocate ***all*** transmission costs, not just SPP costs.

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[187] TIEC Ex. 1, Pollock Dir. at 18-19.

[188] *Id.* at 19.

[189] *Id.*

[190] Tr. at 1211:15-1213:3 (Aaron Cross) (May 25, 2021); TIEC Ex. 74.

SWEPCO has offered no justification whatsoever for changing its jurisdictional allocation for transmission costs other than SPP charges, let alone applying one methodology to Texas and another to Louisiana and Arkansas.

In short, SWEPCO has failed to meet its burden of proof to show the reasonableness of the \$5.7 million transfer of costs from Louisiana and Arkansas to Texas in the jurisdictional allocation study, an issue over which this Commission clearly has jurisdiction.[191] SWEPCO should be directed to use its actual load in calculating the Texas jurisdictional allocator for transmission costs, just as it does for Louisiana and Arkansas.

While the Commission need not reach the issue of whether it has jurisdiction to disallow whatever unknown amount of additional payments to SPP are included in SWEPCO's total company revenue requirement, SWEPCO's argument that the Commission is powerless to disallow such costs is wrong. SWEPCO notes the Commission's prior finding that amounts paid to SPP "pursuant to the SPP OATT" are reasonable.[192] Whatever SWEPCO paid to SPP as a result of SWEPCO's improper decision to increase its Monthly Network Load in Texas was not "pursuant to the SPP OATT." Rather, any such amount is flatly inconsistent with the literal terms of the SPP OATT, as well as a FERC decision interpreting those terms. There is nothing in Commission precedent that says that this Commission must include in rates anything SWEPCO pays to SPP even if it is not "pursuant to the SPP OATT."

One need only carry SWEPCO's argument to its logical conclusion to see that it is wrong. Assume that SWEPCO unilaterally decided that under the SPP OATT, it should multiply its actual load by a factor of 10 in reporting it to SPP, thereby incurring an additional \$500 million in test-year SPP costs. In SWEPCO's view, whether the charges were actually consistent with the tariff would be immaterial, and the Texas Commission would have no choice but to raise Texas rates to include the additional \$500 million. Not surprisingly, SWEPCO cites no authority for such a sweeping proposition. The Commission's statement concerning payments that are actually

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[191] *See supra* section IV.A.6.a; *see also Entergy Texas, Inc.*, 889 F.3d at 209-10.

[192] SWEPCO's In. Br. at 72.

"pursuant to the SPP OATT" certainly does not require such a result.

The other cases cited by SWEPCO do not grant a utility unfettered discretion to ignore the actual terms of a tariff, nor do they deprive the Texas Commission of the ability to disallow payments that were not in fact pursuant to the tariff. In *ELI v. LPSC* cited by SWEPCO, the court specifically stated that "we have no occasion to address the exclusivity of FERC's jurisdiction to determine whether and when a tariff has been violated."[193] In the AEPSC case cited by SWEPCO, the court made clear that the "rate" approved by FERC was the entire System Integration Agreement, and that this agreement authorized only AEPSC to implement the cost-sharing arrangement.[194] Thus, a state's rejection of AEPSC's determination was inconsistent with the FERC tariff.[195] In this case, there is no claim that SWEPCO has been designated by FERC as the sole, official arbiter of the calculations under Section 34.4 of the SPP OATT, and SPP itself disclaims that it has any audit or enforcement responsibility.[196]

In any event, because of how SWEPCO calculated the $5.7 million it shifted to Texas, the issue presented in this case is not actually one of a disallowance of any portion of SWEPCO's payments to SPP for including Eastman's load, but whether to accept an unprecedented jurisdictional allocation method that adds phantom load to Texas but to no other state in allocating total transmission costs, including non-SPP costs. That jurisdictional allocation proposal should be rejected, and the allocators for all three states should be based on SWEPCO's actual load.

E. Purchased Capacity Expense

1. Imputed Capacity for Wind Purchased Power Agreements

As CARD explains in its initial brief, imputing capacity recognizes that some power purchases provide both capacity and energy to SWEPCO, even if the payments made to acquire

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[193] *Entergy Louisiana, Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39, 51 (2003).

[194] *AEP Texas N. Co. v. Texas Indus. Energy Consumers*, 473 F.3d 581, 585 (5th Cir. 2006).

[195] *Id.*

[196] Tr. at 771:15-772:25 (Locke Cross) (May 21, 2021).

those resources are based entirely on a per-kWh charge.[197] SWEPCO's wind purchased power agreements (PPAs) are such power purchases.[198] The wind PPAs provide SPP-accredited capacity that is included in determining whether SWEPCO meets its reserve margin requirements.[199]

While CARD's brief takes issue with Ms. LaConte's quantification of the value of capacity—addressed below and in TIEC's initial brief—it does recognize that, contrary to SWEPCO's and OPUC's assertions, imputing capacity to energy-only contracts is a well-accepted practice. Indeed, SWEPCO's and OPUC's argument that it is not appropriate to impute capacity for the Wind PPAs because they only have an energy charge is entirely circular.[200] Imputing capacity is ascribing capacity value to a contract that does not explicitly charge for capacity; thus, SWEPCO's and OPUC's argument essentially boils down to asserting that it is inappropriate to impute capacity because it is inappropriate to impute capacity. As set out in detail in TIEC's initial brief, there is ample Commission precedent, affirmed by the Third Court of Appeals, establishing that it is appropriate to impute capacity value, even when doing so would result in a disallowance.[201] In this case, imputing capacity would add to SWEPCO's revenue requirement.

SWEPCO also asserts that it is not appropriate to impute capacity for the wind PPAs because they are intermittent.[202] However, Ms. LaConte's recommendation recognizes the intermittency of the resources by ascribing a capacity value to them that is a fraction of their nameplate capacity.[203] The amount of capacity that Ms. LaConte assumed is the same amount that SPP accredits to these resources and that SWEPCO includes when conducting system planning.[204]

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197 CARD's In. Br. at 63.

198 *Id.*

199 TIEC Ex. 4, LaConte Dir. at 23-24.

200 SWEPCO's In. Br. at 102-103; OPUC's In. Br. at 25.

201 TIEC's In. Br. at 64. TIEC notes that there was a typographical error on page 64 and footnotes 365 and 366 in TIEC's initial brief. The citation should have been to Docket No. 23550, not Docket No. 23350.

202 SWEPCO's In. Br. at 102.

203 TIEC Ex. 4, LaConte Dir. at 23-24.

204 *Id.* at 23-24; Tr. at 663:15-18 (Stegall Cross) (May 21, 2021); TIEC Ex. 28.

While SWEPCO argues that SPP's accreditation methodology is "complicated" and thus makes quantifying the amount of capacity difficult,[205] that does not change the fact that the wind PPAs do provide capacity value. Further, SWEPCO did not challenge Ms. LaConte's calculation, which is clear in the record and would be straightforward to adopt.[206]

It is also irrelevant that no party has ever proposed imputing capacity for these particular wind PPAs. The Commission's determination should be based on the evidence presented in this proceeding, and that evidence unequivocally shows that the wind PPAs provide capacity value. That capacity has not been previously imputed for these wind PPAs is not a reason to ignore the evidence presented in this proceeding.

OPUC also makes the erroneous argument that TIEC's recommendation to impute capacity is somehow inconsistent with TIEC's recommendation on retail BTMG.[207] OPUC is mischaracterizing TIEC's arguments on both fronts. With respect to the BTMG issue, TIEC's argument as to the SPP tariff itself is that it does not require SWEPCO to report retail BTMG.[208] As to imputed capacity, TIEC's argument is not that the SPP tariff requires this result, but that the evidence shows that these wind PPAs provide capacity value. The fact that SPP accredits capacity to the wind PPAs is simply evidence that the wind PPAs do indeed provide capacity value to SWEPCO. Further, SWEPCO itself accounts for the capacity provided by the wind PPAs in its integrated resource planning.[209] It is the Commission's fuel rule, not the SPP tariff, that requires capacity-related costs to be recovered in base rates rather than through fuel.[210]

OPUC also contends that capacity should not be imputed because it would shift costs to

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[205] SWEPCO's In. Br. at 102.

[206] TIEC Ex. 4, LaConte Dir. at 26.

[207] OPUC's In. Br. at 25-26.

[208] As discussed above, the BTMG issue in this case boils down to a jurisdictional allocation problem, in that SWEPCO has artificially added the load of a single BTMG customer to the Texas retail jurisdiction in its jurisdictional allocation.

[209] Tr. at 663:15-18 (Stegall Cross) (May 21, 2021).

[210] 16 T.A.C. § 25.236(a)(6).

the residential and small commercial classes.[211] This is a results-oriented approach to ratemaking that is circular in its logic. If the Commission determines that capacity should be imputed to SWEPCO's wind PPAs, then those capacity costs are properly a part of the cost of service in this case. The fact that certain classes are above or below cost has no bearing on the appropriateness of imputing capacity.

Accordingly, the capacity value of SWEPCO's wind PPAs should be imputed and recovered in base rates in this proceeding. The amount of imputed capacity should be calculated using the methodology and value of capacity set forth in Ms. LaConte's testimony. Ms. LaConte's calculation is based on the avoided cost of capacity that the Commission has set by rule to be used in evaluating the cost-effectiveness of energy-efficiency programs.[212] CARD's contentions that this value of capacity is too high is based on stale integrated resource plans (IRPs) that do not account for SWEPCO's recently announced retirements.[213] Further, they rely upon a "market value of capacity" for SWEPCO despite the fact that SPP has no capacity market.[214] CARD's arguments are unavailing and Ms. LaConte's imputed capacity recommendation should be adopted.

2. Cajun Contract

CARD's recommendation to disallow operating reserve capacity payments under the Cajun Contract and recover them through fuel relies upon the faulty premise that those payments are for the same product as operating reserves purchased in the SPP.[215] As SWEPCO witness Mr. Stegall explained, the operating reserve capacity purchased under the Cajun contract is capacity that is used to help fulfill SWEPCO's SPP reserve margin requirements.[216] On the other hand, "operating

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211 OPUC's In. Br. at 24.

212 16 T.A.C. § 25.181(d)(2).

213 TIEC's In. Br. at 63.

214 CARD's In. Br. at 65; TIEC's In. Br. at 63; Tr. at 1111:19-1112:20 (Norwood Cross) (May 25, 2021).

215 CARD's In. Br. at 62-63.

216 SWEPCO Ex. 47, Rebuttal Testimony of Jason M. Stegall at 7-9 (Stegall Reb.); *see also* TIEC Ex. 28 at Bates 003 (showing that the 50 MW of purchases under the Cajun contract reduces SWEPCO's load responsibility by 50 MW).

reserves" in the SPP are an ancillary service that is procured in the day-ahead and real-time market.[217] Similar to energy, operating reserves are economically cleared in the SPP Integrated Marketplace (IM) based on bids and offers submitted by Market Participants.[218] Operating reserves in the SPP must be purchased through the IM, not through bilateral contracts.[219] Thus, the operating reserve capacity in the Cajun Contract is an entirely different product than operating reserves in the SPP IM. The operating reserve capacity in the Cajun Contract is related to capacity, and therefore properly recovered in base rates.[220] CARD's brief does not address this fundamental distinction,[221] and its recommendation to disallow the Cajun Contract capacity payments should be rejected.

VI. Functionalization and Cost Allocation [PO Issues 4, 5, 52, 53, 55, 56, 57, 58]

A. Jurisdictional Allocation [PO Issues 55, 57]

SWEPCO improperly included BTMG load in Texas's jurisdictional allocator for transmission costs, resulting in an inflated Texas jurisdictional allocator that shifts $5.7 million of transmission costs from Arkansas and Louisiana to Texas ratepayers.[222] Notably, SWEPCO did not include any BTMG load for Arkansas and Louisiana, despite acknowledging the existence of cogeneration facilities and BTMG load in those states,[223] nor did it include BTMG load for Texas in its recent rate cases before those jurisdictions.[224] SWEPCO's improper jurisdictional allocation of transmission costs is briefed in greater detail in Section IV.A.6.a above and should be rejected for the reasons stated therein.

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217 SWEPCO Ex. 47, Stegall Reb. at 8.

218 *Id.*

219 *Id.* at 9.

220 *Id* at 7-9.

221 CARD's In. Br. at 62-63.

222 TIEC Ex. 74.

223 Tr. at 1212:8-1213:4 (Aaron Cross) (May 25, 2021).

224 *Id.* at 1197:7-17.

B. Class Allocation [PO Issues 53, 58]

TIEC urges the Commission to adopt Mr. Pollock's proposed revisions to SWEPCO's class cost-of-service study (CCOSS).[225] TIEC addresses various cost-allocation arguments raised by other parties in this section of its brief,[226] most notably SWEPCO's improper proposal to impute Eastman's BTMG load in the Large Lighting and Power-Transmission (LLP-T) class for allocation purposes.

1. System Load Factor

No party took issue with SWEPCO's correction to its CCOSS to use a system load factor that is based on the single coincident peak. As Mr. Pollock explained in his testimony, the use of a system load factor based on a single coincident peak is consistent with cost causation and precedent, and should be approved.[227]

2. Allocation of BTMG load in the Class Cost of Service Study (CCOSS)

SWEPCO's proposal to impute Eastman's BTMG-served load into the LLP-T customer class should be rejected.[228] The record evidence is that Eastman serves its own load with a 400-plus MW combined-cycle gas turbine (CCGT) plant.[229] Since 2013, this CCGT facility has generated more electricity than Eastman consumed in all but three months.[230] And the facility generated more power than Eastman's coincident demand with the SPP Zone 1 system peaks in

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[225] *See* TIEC's In. Br. at 65-75.

[226] In addition to the issues discussed below, TIEC notes that SWEPCO argues that Mr. Pollock incorrectly stated that SWEPCO's transmission allocation factors were based on SPP Zone 1 peak demands rather than SWEPCO system peak demands. SWEPCO's In. Br. at 117. Mr. Pollock accepted Mr. Aaron's rebuttal testimony on this point and removed this contention from his testimony through his second errata. *See* TIEC Ex. 1, Pollock Dir. at 32.

[227] TIEC Ex. 1, Pollock Dir. at 32-34.

[228] As explained in Section IV.A.6 of TIEC's briefing, the threshold flaws in SWEPCO approach include that: (1) the SPP OATT does not call for the inclusion of BTMG-load in SPP member Monthly Network Reports; (2) SWEPCO has engaged in unlawful discrimination by choosing to report only Eastman's BTMG load to SPP, despite the fact that it has numerous other retail BTMG customers in Texas and its other jurisdictions; and (3) SWEPCO is essentially treating Eastman as if it were always in an outage during times of peak, which violates both federal and state regulations governing Qualified Facilities.

[229] TIEC Ex. 1, Pollock Dir. at 24.

[230] *Id.*

all 12 months of the test year.[231] As Mr. Pollock summarized, "there is no evidence that Eastman's load requires any network transmission service during the SWEPCO and SPP Zone 1 monthly system peaks."[232] Nevertheless, SWEPCO proposes to treat Eastman in the CCOSS as if it were a 98% load factor customer purchasing full service on the LLP-T rate schedule.[233] This has the effect of more than doubling the transmission allocator for LLP-T,[234] and, under SWEPCO's proposal, only a portion of the resulting increased costs would be assigned to Eastman itself.[235]

As discussed below, no party offered a credible defense of SWEPCO's BTMG-allocation proposal in their initial briefs, and that proposal should be rejected. Even if the Commission were to allow SWEPCO to shift $5.7 million from Arkansas and Louisiana to Texas by including Eastman's self-served load in the jurisdictional allocation study, it should still remove Eastman's imputed load from the LLP-T customer class in the CCOSS. In that event, SWEPCO should create a separate class for all BTMG loads for cost-allocation purposes.[236]

a. SWEPCO's proposal does not accurately quantify the impact of including Eastman's BTMG load in SWEPCO's SPP Load Ratio Share.

Despite its importance, and the lack of clarity around its proposal, SWEPCO barely bothers to address the BTMG-allocation issue in its brief, arguing in passing that the transmission allocator it applied "reflects the appropriate allocation to classes based on costs billed to SWEPCO by SPP

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[231] *Id.*

[232] *Id.*

[233] *Id* at 32, 37.

[234] SWEPCO Ex. 54, Rebuttal Testimony of John O. Aaron at Ex. JOA-1R (Aaron Reb.). This exhibit shows the production and transmission demands by class. As Mr. Aaron explained, the only difference between the peak demand shown for production and transmission for each class is that 149 MW was added to the LLP-T class to account for BTMG. *Id.* at 3.

[235] TIEC Ex. 78 at Bates 002; *see also* Tr. at 1252:13-19 (Jackson Cross) (May 25, 2021) (discussing this dynamic with respect to SWEPCO's original proposal, under which Eastman was assigned $3.96 million).

[236] TIEC Ex. 1, Pollock Dir. at 39.

for transmission costs incurred to serve its customers classes."[237] That is incorrect. In fact, SWEPCO's proposed transmission allocator is not even based on changes in SPP charges caused by including Eastman's BTMG load in SWEPCO's load ratio share.[238]

Critically, SWEPCO's explanation ignores the fact that the "costs billed to SWEPCO by SPP" (which are sometimes referred to as Approved Transmission Charges or ATC) are only a subset of SWEPCO's transmission revenue requirement. As explained in Mr. Pollock's testimony, SWEPCO's transmission costs also include items such as return and depreciation on SWEPCO's transmission invested capital.[239] Indeed, more than one-third of SWEPCO's transmission revenue requirement is comprised of components other than SPP charges.[240] SWEPCO's rationale for changing its transmission allocation to account for BTMG load is that it is required to report this load to SPP by the SPP OATT.[241] Even if that were true, however, the consequence would be to increase SWEPCO's share of SPP's costs.[242] Thus, even if SWEPCO were required to include Eastman's BTMG load in its SPP reports (notwithstanding the fact that it is self-served), this would only provide a justification for changing the allocation of SWEPCO's SPP charges; not for reallocating the entirety of SWEPCO's transmission revenue requirement.[243] Indeed, neither

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[237] SWEPCO's In. Br. at 117. SWEPCO devotes a single paragraph in its 145 page brief to defending its BTMG-allocation proposal, which, as discussed below results in a massive and unsupported cost shift to the LLP-T class.

[238] TIEC Ex. 1, Pollock Dir. at 25; TIEC Ex. 2, Pollock Supp. Dir. at 2.

[239] TIEC Ex. 2, Pollock Supp. Dir. at 2.

[240] *Id.*

[241] SWEPCO Ex. 32, Direct Testimony of Jennifer L. Jackson at 15 (Jackson Dir.); ("SWEPCO is also introducing a provision to the SBMAA rate schedules designed to recover the cost of customers with self-generation synchronized with the SWEPCO transmission system whose load is required to be included in SWEPCO's load ratio share from the Southwest Power Pool (SPP)"); SWEPCO Ex. 55, Rebuttal Testimony of Jennifer L. Jackson at 12-13 (Jackson Reb.).

[242] TIEC Ex. 1, Pollock Dir. at 13-15; *see also* SWEPCO Ex. 52, Rebuttal Testimony of C. Richard Ross at Bates 8 (Ross Reb.) ("In its simplest form, the cost for the use of the SPP Transmission System is allocated by SPP to NITS customers based on the ratio of each customer's monthly load to the total system load at the time of the monthly system peak."); SWEPCO Ex. 55, Jackson Reb. at 12-13 (explaining that SWEPCO's proposed SSGL charge was "proposed to recover additional costs associated specifically with the inclusion of BTMG load in determining SWEPCO's share of the Southwest Power Pool (SPP) transmission costs.").

[243] Tr. at 1358:4-19 (Pollock Redir.) (May 25, 2021).

SWEPCO nor any other party has provided any rationale in this case for changing the allocation of SWEPCO's non-SPP costs based on an interpretation of the SPP OATT. And the Commission has not included BTMG load in deriving the A&E/4CP transmission allocator for SWEPCO in the past.[244]

Nevertheless, that is what SWEPCO proposes.[245] The mechanics of this approach are evident in Mr. Aaron's CCOSS. Because SWEPCO uses the A&E/4CP methodology for both production and transmission demand, each class should theoretically have the same allocation factor for both functions.[246] However, that changed because SWEPCO imputed Eastman's 149 MW of BTMG-served load to the LLP-T transmission demand.[247] Thus, while LLP-T has a production demand allocator of 6.6% in SWEPCO's rebuttal CCOSS, it has a transmission allocation factor of more than double that at 14.3%.[248] Meanwhile, every other class would see a reduced transmission allocator as a result of SWEPCO imputing Eastman's BTMG-served load to the LLP-T class.[249]

In terms of allocating costs, the impact on LLP-T is both severe and inexplicable. While SWEPCO estimates that including Eastman's BTMG load in its Monthly Network Load reports to SPP increased the Texas retail revenue requirement by $5.7 million, it apparently proposes to allocate $8 million of this $5.7 million amount to the LLP-T class.[250] That proposal makes no

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[244] TIEC Ex. 1, Pollock Dir. at 32.

[245] SWEPCO Ex. 31, Aaron Dir. at 17-18.

[246] *Id.* at 18; SWEPCO Ex. 54, Rebuttal Testimony of John O. Aaron at 3 (Aaron Reb.).

[247] SWEPCO Ex. 31, Aaron Dir. at 18; *see also* SWEPCO Ex. 54, Aaron Reb. at 3, JOA-1R (showing the addition of 149 MW of demand to the LLP-T transmission demands).

[248] SWEPCO Ex. 54A, Workpapers to the Rebuttal Testimony of John O. Aaron at "JOA WP – SWEPCO TX COS_Class TY 3_2020 Rebuttal.xlsx," Tab TX CLASS, Cells V15 & V17 (Aaron Reb. Workpapers). The same dynamic can be seen in Mr. Aaron's exhibit JOA-4, but this reflects SWEPCO's as-filed CCOSS, which included the inadvertent error regarding the system load factor. SWEPCO Ex. 31, Aaron Dir. at 18; SWEPCO Ex. 54, Aaron Reb. at 3 ("SWEPCO inadvertently applied an average demand system load factor as calculated on Schedule O-1.6 rather than the single annual peak demand load factor.").

[249] SWEPCO Ex. 54A, Aaron Reb. Workpapers at "JOA WP – SWEPCO TX COS_Class TY 3_2020 Rebuttal.xlsx," Tab TX CLASS, Rows 15 & 17 (showing that each class other than LLP-T has a lower transmission allocation factor than production allocation factor).

[250] TIEC Ex. 74 at Bates 002; TIEC Ex. 76.

more sense from a cost-causation standpoint than it does a linguistic one. But that is SWEPCO's analysis, as detailed in TIEC Ex. 74, which is reproduced in pertinent part as Attachment A to this brief for the ALJs' reference. As can be seen, SWEPCO's analysis shows that including Eastman's BTMG-load in the LLP-T class increases that class's share of allocated costs by nearly $8 million, while reducing all other classes' share by a total of approximately $2.3 million.[251]

As demonstrated by the foregoing, SWEPCO's CCOSS does not identify and allocate the actual impact of its decision to include Eastman's BTMG load in SWEPCO's Monthly Network Load reports to SPP.[252] Instead, SWEPCO has simply reallocated its entire transmission revenue requirement based on imputing Eastman's BTMG load in the LLP-T class. Having failed to identify the extent to which its SPP charges (the only costs impacted by reporting Eastman's load) increased, SWEPCO has failed to meet its burden of proving that any additional costs related to Eastman's BTMG load should be allocated to any class.

b. Neither cost causation nor fairness supports pretending that the Eastman's BTMG load is part of LLP-T's transmission demand.

SWEPCO also argues that "excluding the retail BTMG load from the class that has that load would inappropriately shift the transmission costs incurred by SWEPCO to other classes that should not be responsible for those transmission costs."[253] But SWEPCO has failed to explain why the LLP-T class should bear responsibility for costs associated with Eastman's BTMG load. Indeed, SWEPCO's proposed treatment is inconsistent with its own cost-allocation witnesses' definition of "cost causation." Mr. Aaron testified that "[m]y definition of cost causation is the customers that causes the cost should also bear the responsibility of that cost in the allocation and in rates."[254] If any customer "caused" costs relating to SWEPCO's decision to include Eastman's BTMG-load in its SPP network reports, it is Eastman itself. There is no basis in cost causation to

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[251] *See* TIEC Ex. 74, Attachment 1; Tr. at 1363:6-1364:4 (Pollock Redır.) (May 25, 2021).

[252] *See* SWEPCO Ex. 54A, Aaron Reb. Workpapers at "JOA WP – SWEPCO TX COS_Class TY 3_2020 Rebuttal.xlsx," Tab TX CLASS.

[253] SWEPCO's In. Br. at 117-118.

[254] Tr. at 1221:6-9 (Aaron Cross) (May 25, 2021).

allocate costs purportedly associated with Eastman's BTMG-load to LLP-T customers who have nothing to do with that load or SWEPCO's decision to report it to SPP.

Indeed, BTMG customers are not like LLP-T customers and thus should not be included in the same class for cost-allocation purposes.[255] As Mr. Pollock testified, a CCOSS should group customers into homogenous classes according to their usage patterns and service characteristics.[256] LLP-T customers purchase large amounts of electricity from SWEPCO at a very high load factor.[257] Eastman, by contrast, rarely purchases power from SWEPCO because it serves its own load with BTMG.[258] In fact, none of Eastman's load on SWEPCO's system occurred coincident with SWEPCO's peaks during the test year.[259] Full service LLP-T customers bear no resemblance to BTMG customers like Eastman, and combining them into the same class for cost-allocation purposes results in improper subsidies between full-service and retail BTMG customers.[260] Indeed, at the hearing, Ms. Jackson acknowledged that LLP-T customers already pay for their share of SWEPCO's transmission system.[261] Nevertheless, under SWEPCO's current BTMG-allocation proposal, these customers would also be asked to pay millions more related to Eastman's BTMG load.[262]

Notably, while Eastman's service characteristics are not like those of LLP-T customers (or of any other full-service customers), SWEPCO does have numerous other retail customers—nearly 200—that serve at least a portion of their own loads through BTMG.[263] These customers are

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[255] This would continue to be true even if the SSGL rate were approved, as it would be an unbundled network transmission rate that is unlike the bundled service that SWEPCO provides to LLP-T customers. SWEPCO Ex. 55, Jackson Reb at 13-14 (explaining the development of the SSGL rate based on the transmission functional cost).

[256] TIEC Ex. 1, Pollock Dir. at 26.

[257] *Id.* at 28-29.

[258] *Id.* at 37-38.

[259] *Id* at 38.

[260] *Id.* at 39.

[261] Tr. at 1254:2-10 (Jackson Cross) (May 25, 2021).

[262] TIEC's In. Br. at 85; Tr. at 1254:2-6 (Jackson Cross) (May 25, 2021); TIEC Ex. 78.

[263] TIEC Ex. 2, Pollock Supp. Dir. at JP-S1 at 2-5.

located in various customer classes and have BTMG of various sizes.[264] While SWEPCO has chosen to report only Eastman's load to SPP at this point, there is no distinction in the SPP OATT that would support reporting only BTMG of a certain size or that is "synchronized" to the SPP system while not reporting all other BTMG.[265] Accordingly, if the Commission decides to allow SWEPCO to charge retail BTMG customers for SPP network transmission service, it should create a separate class comprised of all BTMG loads.[266] Indeed, SWEPCO seems to acknowledge that this could be an appropriate approach, given that it has designed its rebuttal synchronous self-generation load (SSGL) charge to be applicable to all BTMG loads, and has now acknowledged that it would be appropriate for this charge to be on its own rate schedule since it is not limited to standby service.[267]

In a similar vein to SWEPCO's misplaced cost-causation contentions, ETSWD repeatedly states that it opposes any proposal that would shift "SPP OATT costs associated with behind-the-meter generation customers in the industrial class to any other Texas Retail customer class, including the Oilfield Services class."[268] In this connection, Ms. Pevoto, in her cross-rebuttal testimony, opposed Mr. Pollock's recommendation to remove the BTMG load from the LLP-T demand on the basis that doing so would purportedly violate cost-causation principles.[269] However, at the hearing Ms. Pevoto agreed that non-Eastman LLP-T customers do not cause costs relating to Eastman's BTMG load any more than any other customers do:

> Q Okay. And then on the next page -- or the next sentence, you state that: "Mr. Pollock's recommendation does not follow cost causation principles because they would shift costs incurred as a result of Eastman's presence on the system to

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[264] *Id.*

[265] TIEC Ex. 1, Pollock Dir. at 22; TIEC Ex. 2, Pollock Supp. Dir. at 4.

[266] TIEC Ex. 1, Pollock Dir. at 39.

[267] SWEPCO Ex. 55, Jackson Reb. at 14.

[268] ETSWD's In. Br. at 7.

[269] Tr. at 1302:5-23 (Pevoto Redir.) (May 25, 2021).

other SWEPCO retail customers who do not cause them."
Did I read that correctly?

A That is what my testimony on this page, yes.

Q Yes. And -- but LLP-T customers other than Eastman don't cause those costs, either. Right?

A No, they do not.[270]

Ms. Pevoto's support for allocating BTMG costs to the LLP-T class might be premised on a misunderstanding that the BTMG costs would be directly assigned to Eastman in the rate-design process.[271] However, that is not SWEPCO's proposal, as Ms. Jackson expressly notes in her testimony.[272] In fact, SWEPCO's rebuttal SSGL charge would recover only $3.27 million annually from Eastman,[273] apparently leaving some amount in the range of $4 million of the BTMG-load costs to be recovered from other LLP-T customers who are mere bystanders with respect to Eastman's BTMG load.[274] There is no basis in cost causation to shift these costs to LLP-T customers who have nothing to do with Eastman's BTMG load.

3. Reply to CARD on Major Account Representatives

In this section of its brief, CARD argues that two adjustments SWEPCO made in its rebuttal CCOSS were improper, although CARD's heading only refers to one of them.[275] CARD's contentions are incorrect.

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270 Tr. at 1298:2-12 (Pevoto Cross) (May 25, 2021).

271 Tr. at 1302:5-23 (Pevoto Redir.) (May 25, 2021).

272 SWEPCO Ex. 55, Jackson Reb. at 13 ("Instead of directly assigning the cost associated with the inclusion of the BTMG to those customers, SWEPCO proposed to create a new charge that applies to any commercial/industrial BTMG customer load that may also be included in SWEPCO's load ratio share.").

273 Tr. at 1504:22-1505:1 (Jackson Cross) (May 26, 2021).

274 TIEC Ex. 78; Tr. at 1254:2-6 (Jackson Cross) (May 25, 2021); *see also* Tr. at 1252:13-19 (Jackson Cross) (May 25, 2021) (discussing this dynamic with respect to SWEPCO's original proposal, under which Eastman was assigned $3.96 million).

275 CARD's In. Br. at 68-69. CARD's heading is "SWEPCO's Improper Adjustment to the Allocation of Major Account Representative Costs," though CARD also argues against an adjustment to Test-Year prepayment balances. *Id.*

In its rebuttal case, SWEPCO presented several adjustments and corrections to its CCOSS.[276] Among other things, SWEPCO corrected the components of Test-Year prepayment balances included in rate base[277] and the quantification and allocation of costs recorded in FERC Account 908.[278] CARD claims for the first time in its initial brief that these changes "do not appear" to be consistent with the allocation factors approved in Docket No. 46449.[279] CARD further implies that these adjustments improperly increased the costs allocated to the Residential class by $626,000, referencing a chart contained in Mr. Aaron's rebuttal testimony.[280]

As an initial matter, the chart in Mr. Aaron's rebuttal testimony includes all of the adjustments that SWEPCO made to its CCOSS between the direct and rebuttal case, including changing the requested revenue requirement and correcting its system load factor to be based on the single annual coincident peak—a change that CARD did not oppose in its brief.[281] Thus, CARD's inclusion of this chart in this section of its brief is misleading.

Moreover, CARD's contentions regarding the two adjustments of which it complains are unsupported and inaccurate. CARD argues that the adjustments are inconsistent with the Commission's decision in Docket No. 46449. However, the only support it offers for that proposition is a citation to a section of the Order on Rehearing in that case where the Commission determined that it is appropriate for major account representatives to be directly assigned to the large commercial and industrial classes.[282] This has nothing to do with Test-Year prepayment balances including in rate base, and CARD does not offer any explanation to the contrary.

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[276] SWEPCO Ex. 54, Aaron Reb. at 3-7.

[277] *Id.* at 7.

[278] *Id.*

[279] CARD's In. Br. at 68-69.

[280] *Id.* at 69.

[281] SWEPCO Ex. 54, Aaron Reb. at 3-6.

[282] CARD's In. Br. at 69 n.347 (citing Docket No. 46449, Order on Rehearing at 47).

Further, SWEPCO's adjustment to FERC Account 908 does not run afoul of the Commission's order in Docket No. 46449. As Mr. Aaron explained in his rebuttal CCOSS, SWEPCO did in fact allocate major account representatives to the large commercial and industrial customers that use them, as the Commission ordered in that case.[283] The rebuttal adjustment to Account 908 was merely to remove certain labor expenses that are ***not*** related to major account representative expenses from the direct assignment to these customers.[284] CARD has not provided any basis for the Commission to reject this adjustment.

4. Reply to OPUC

In this section of its brief, OPUC states that the residential class's relative rate of return is higher than that of the "large industrial customer class" under current rates, though OPUC does not appear to request any specific relief on that point.[285] TIEC simply notes that OPUC is referring to SWEPCO's as-filed CCOSS study.[286] SWEPCO's rebuttal CCOSS includes a number of revisions, including the application of the correct system load factor calculated based on a single coincident peak.[287] As shown in Mr. Pollock's testimony, when proper revisions are made, the residential class is shown as having a lower relative rate of return than, for example, the LLP-T customer class.[288]

5. Reply to ETSWD's COVID-19 Adjustment

TIEC joins with the other parties in opposing ETSWD's proposal to "update" the test-year

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[283] SWEPCO Ex. 54A, Aaron Reb. Workpapers at "JOA WP – SWEPCO TX COS_Class TY 3_2020 Rebuttal.xlsx," Tab COS Changes – Discovery, Lines 69-72, 100-108 (reproducing SWEPCO's response to TIEC 7-1(d)); *see also* SWEPCO Ex. 54, Aaron Reb. at 7 (explaining that the adjustment to FERC Account 908 was set forth in SWEPCO's Response to TIEC 7-1(d)).

[284] SWEPCO Ex. 54A, Aaron Reb. Workpapers at "JOA WP – SWEPCO TX COS_Class TY 3_2020 Rebuttal.xlsx," Tab COS Changes – Discovery, Lines 73-76 (reproducing SWEPCO's response to TIEC 7-1(d)).

[285] OPUC's In. Br. at 27-28.

[286] *Id.* (citing SWEPCO Ex. 32, Jackson Dir. at Exhibit JLJ-1 at 2.

[287] SWEPCO Ex. 54, Aaron Reb. at 3.

[288] TIEC Ex. 1, Pollock Dir. at Exhibit JP-3 at 2 of 4, 3 of 4 (showing Residential Basic with a relative rate of return of 97 and showing LLP-T having a relative rate of return of 207).

billing determinants to account for the COVID-19 pandemic.[289] ETSWD has not demonstrated that its proposal is known and measurable. Nor has it provided a specific adjustment, leaving it unclear how the Commission would implement this recommendation if it were inclined to do so. TIEC would note that parties are entitled to review, analyze, and take positions on any data used to set rates in this case, and it is unclear how they would have that opportunity under ETSWD's proposal.

VII. Revenue Distribution and Rate Design [PO Issues 4, 5, 47, 48, 52, 59, 60, 61, 62, 75, 76, 77, 78, 79]

A. Rate Moderation / Gradualism [PO Issue 52]

Most of the parties to this case address their preferred approach to revenue distribution in their initial briefs. TIEC will not respond to each parties' briefs individually, but will lay out its proposed revenue-distribution framework while responding to certain points raised by other parties. TIEC also addresses the potential need for gradualism with respect to SWEPCO's BTMG proposals.

- **The Revenue-Distribution Process**

The revenue distribution process should start with the use of the proper rate classes. Mr. Pollock proposes the use of 13 rate classes, which correspond to the rate schedules that SWEPCO proposes in this case.[290] Commission Staff urges the adoption of its revenue-distribution proposal, which like SWEPCO's, utilizes more granular classes.[291] Specifically, it appears that Staff's proposal would use 19 classes for revenue-distribution purposes.[292] As with SWEPCO's proposal, several of Staff's proposed classes take service under the same rate schedule.[293] This approach

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[289] ETSWD's In. Br. at 2-7, 8.

[290] TIEC Ex. 1, Pollock Dir. at JP-4. Due to the multiple lighting rate schedules, Mr. Pollock used the lighting class as designed in SWEPCO's CCOSS. *Id.* at 45.

[291] Staff's In. Br. at 70-72; Staff Ex. 4, Direct Testimony of Adrian Narvaez at 23-25 (Narvaez Dir.).

[292] Staff Ex. 4, Narvaez Dir. at Attachment AN-6.

[293] *Id.* For example, Staff's proposed distribution has Lighting and Power Secondary and Primary as separate classes, but both fall under the same rate schedule. TIEC Ex. 1, Pollock Dir. at 44.

creates some rate classes with very low populations, as shown in Table 6 of Mr. Pollock's testimony:[294]

Table 6 Year-End Customer Count: Low Population Customer Classes[295]	
Customer Class	**Amount**
Cotton Gin	8
General Service DG	5
Light & Power DG	11
Large Lighting & Power: Primary	2
Large Lighting & Power: Transmission	6
Metal Melting Dist. Voltages	6
Metal Melting ≥ 69 kV	1

The problem with low population rate classes is that changes in the characteristics of just one or two customers during the test year can have a significant impact on the revenue-allocation process.[296] The more reasonable approach for this case would be to use rate classes that correspond to rate schedules for revenue-distribution purposes.[297] This mitigates the concern with rate classes that are too granular (though it still results in 13 distinct classes), and better comports with the Commission's rules.[298]

Mr. Pollock proposes that each rate schedule should be moved to cost, limited only by gradualism.[299] There appears to be a consensus among the parties that rates should generally be moved to cost, subject to gradualism. The parties, however, do not agree on the precise parameters

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[294] TIEC Ex. 1, Pollock Dir. at 45.

[295] Schedule O-1.1.

[296] *Id.*

[297] *Id.*

[298] The Commission's rules define "Rate Class" as "[a] group of customers taking electric service under the same rate schedule." 16 T.A.C. § 25.5(100).

[299] TIEC Ex. 1, Pollock Dir. at 7, 46.

of a gradualism constraint.[300] For his part, Mr. Pollock proposed to cap the rate increase at 42.6% for two classes that are currently providing a negative rate of return and would otherwise receive excessive increases.[301] This 42.6% increase is the maximum that the Commission approved in SWEPCO's last rate case, Docket No. 46449.[302] Given its preference for cost-based rates,[303] it is unclear at this point whether the Commission will decide that any gradualism constraint is appropriate in this case. That decision will turn on a number of factors, including the resolution of the various revenue-requirement and cost-allocation issues. However, TIEC submits that Mr. Pollock's proposed gradualism constraint is a reasonable guideline at this stage in the case.[304]

There is also disagreement among the parties as to how any revenue shortfall created by the application of a gradualism constraint should be treated. Mr. Pollock's proposal is that any such subsidy should be spread to the other non-capped rate classes in proportion to their base rate increases.[305] Nucor witness Mr. Daniel proposes that any shortfall created by gradualism should be proportionally assigned to rate classes that received a below average rate increase.[306] SWEPCO, on the other hand, proposes to keep any subsidy within the "major class" groups that

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[300] For example, Nucor proposes a cap of 1.5 times the system average increase (Nucor's In. Br. at 7), the Texas Cotton Ginners Association (TCGA) request a rate increase of no more than the lower of the system average increase or no more than 37.44% for their class (TCGA's In. Br. at 36), and TIEC (TIEC's In. Br. at 79), Staff (Staff's In. Br. at 73) and SWEPCO (SWEPCO's In. Br. at 122) all propose caps of approximately 43%, with SWEPCO's proposal excluding TCRF and DCRF revenues.

[301] TIEC Ex. 1, Pollock Dir. at 46. Mr. Pollock's proposal includes TCRF and DCRF revenues in present base revenues for purposes of calculating the increase. *Id.* at 7.

[302] *Id.* at 46.

[303] *E.g.*, Docket No. 46449, PFD at 356.

[304] TIEC opposes Staff's unprecedented proposal to implement a rate increase of up to 42.6% per year for four years as part of a gradualism phase-in approach. Staff's In. Br. at 74-75. Staff has not demonstrated that this extraordinary remedy is necessary under the facts of this case. TIEC shares the concerns of multiple other parties that this proposal would be administratively difficult and unpredictable, and that increasing rates in his manner could result in rate shock. Staff argues that this type of approach has been used in water cases, but Staff has made no showing that the impact to customers would be similar in the electricity context. In particular, this type of proposal should not be imposed on Eastman in the event that the Commission approves a BTMG load charge of the kind that SWEPCO proposes.

[305] TIEC's In. Br. at 79-80; Tr. at 1359:21-1360:5 (Pollock Redir.) (May 25, 2021) (describing this approach to spreading the impact of a subsidy to all remaining classes).

[306] Nucor's In. Br. at 7.

SWEPCO created.[307] Staff accepted this approach in its revenue-distribution proposal,[308] and CARD defends it in its brief.[309] However, that grouping approach should not be followed in this case.

No party in this case has provided any credible rationale for limiting the impact of a subsidy created by a gradualism cap to only those rate classes that happen to have been grouped into a "major class." To the contrary, the evidence shows that SWEPCO's grouping approach is both ad hoc (Ms. Jackson testified that SWEPCO comes up with its groups ***after*** it has run the CCOSS[310]) and, in this case at least, quite arbitrary. As Nucor witness Mr. Daniel testified, "[t]here is no logical basis for SWEPCO's Groups of customer classes which include extremely different customer sizes, types, load characteristics and rate structures."[311] This is certainly true of the so-called Commercial & Industrial class, which includes members as disparate as General Service, Cotton Gin, Metal Melting, Oilfield, and Large Lighting and Power.[312] As Mr. Daniel explained, this Commercial & Industrial bundle is not a group of similarly situated customers:

> This combined Group of rate classes includes a very diverse Group of customers. Some customers in this "major" customer class or Group receive service at distribution secondary and primary voltages and at transmission voltage. Some customers have seasonal energy requirements while other customers have relatively constant energy requirements throughout the year. One rate class's average annual energy usage per customer is approximately 6,000 kWh while another rate class's average annual energy usage per customer is over 136,000,000 kWh. Approximately 35% of the customers in this Group do not even get billed a demand charge.[313]

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307 SWEPCO's In. Br. at 122.

308 Staff Ex. 4, Narvaez Dir. at 20.

309 CARD's In. Br. at 73-74.

310 SWEPCO Ex. 32, Jackson Dir. at 10-11; Tr. at 1255:16-19 (Jackson Cross) (May 25, 2021).

311 Nucor Ex. 1, Direct Testimony of James W. Daniel at 10 (Daniel Dir.).

312 SWEPCO Ex. 32, Jackson Dir. at 11; Nucor Ex. 1, Daniel Dir. at 7.

313 Nucor Ex. 1, Daniel Dir. at 11.

SWEPCO's proposal to keep any rate subsidies within the major class would also apparently only apply to certain classes. At the hearing, Ms. Jackson admitted that if the Residential class ever needed a gradualism cap, there would be no way to limit the resulting subsidy to a "major class."[314] Accordingly, SWEPCO would in that instance spread the impact of the revenue shortfall to all other classes.[315] This underscores the extent to which this grouping methodology is not truly a uniformly applied principle. Indeed, both Staff and ETSWD witness Ms. Pevoto have recommended spreading the revenue shortfall caused by a gradualism constraint to classes without reference to major groups in prior cases.[316]

While the Commission approved a form of grouping in SWEPCO's last rate case, the proper application of gradualism is a fact-specific inquiry.[317] And, in any event, SWEPCO changed its grouping proposal in this case,[318] and then changed it again in rebuttal.[319] The Commission has applied gradualism without using major rate groups in the past (for example, by setting a cap and floor for all classes[320]). Thus, the rote application of "precedent" does not support keeping a subsidy within a major class in this case.

Ultimately, there is no basis in either cost-causation or fairness to focus the impact of a gradualism subsidy on just the rate classes that were arbitrarily grouped together for purposes of this case. The Commission should adopt Mr. Pollock's proposal to spread the impact of any

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314 Tr. at 1256:10-24 (Jackson Cross) (May 25, 2021).

315 *Id.*

316 TIEC Ex. 82; TIEC Ex. 83.

317 Tr. at 1375:24-1376:1 (Narvaez Cross) (May 26, 2021) (agreeing that it is a judgment call how to spread gradualism revenue shortfalls to other classes); Tr. at 1296:20-23 (Pevoto Cross) (May 25, 2021) (agreeing that there is more than one reasonable way to do a gradualism adjustment).

318 Tr. at 1255:10-15 (Jackson Cross) (May 25, 2021) (agreeing that the grouping of major classes differed in what was proposed in SWEPCO's last two rate cases); Nucor Ex. 1, Daniel Dir. at 10-11.

319 Tr. at 1256:6-9 (Jackson Cross) (May 25, 2021) (agreeing that she proposed a different moderation in her rebuttal).

320 TIEC's In. Br. at 80; *see, e g., Application of Gulf States Utilities Company for a Rate Increase*, Docket No. 5560, Revised Examiner's Report, 1984 WL 274017 at *104 (ordering a gradualism limitation of no less than 0.5 times the system average and no greater than 1.5 times the system average without using major rate class groupings).

gradualism constraint approved in this case to all non-capped classes.

The final step in the revenue-distribution process is to set a revenue requirement and rate for each service within a rate schedule.[321] As Mr. Pollock testified, this rate-design process should be informed by the results of the CCOSS.[322] No party has opposed Mr. Pollock's testimony on this point.

- **Gradualism with Respect to BTMG-Load Proposals**

Gradualism may be particularly necessary in this case to the extent that the Commission approves SWEPCO's proposal to account for Eastman's BTMG load when establishing (and charging customers for) SWEPCO's transmission revenue requirement. As discussed in TIEC's initial brief,[323] the base rate increase for Eastman under SWEPCO's as-filed proposal would have been over 140%,[324] and the increase under SWEPCO's rebuttal proposal would be 121%.[325] If the $5.7 million SWEPCO quantifies as the impact of including Eastman's BTMG were directly assigned to Eastman, it would result in an increase of nearly 200%.[326] These rate increases would constitute rate shock under any reasonable definition, but ETSWD nevertheless attempts to cast doubt on whether Eastman should receive any rate moderation even if these types of proposals were adopted.[327] ETSWD's efforts are meritless.

To begin with, ETWSD misstates TIEC's position on this issue. Specifically, ETSWD argues that Mr. Pollock's proposal is to "shift more than 90% of the SPP OATT-related

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[321] TIEC Ex. 1, Pollock Dir. at 45.

[322] *Id.* at 45-46; *see also* TIEC's In. Br. at 79 (explaining TIEC's proposal on this point).

[323] TIEC's In. Br. at 88.

[324] TIEC Ex. 1, Pollock Dir. at 51.

[325] TIEC Ex. 1A, Pollock Dir. Workpapers at "WP Eastman Impact TIEC_11-7_Attachment_1.xslx." If the $2.20/kW charge in cell C19 in this spreadsheet is changed to $1.82/kW, the resulting net increase of 143% shown in cell S20 decreases to 121%.

[326] *Id.* If the $3.96 million recovered under the SSGL in cell R19 in this spreadsheet is changed to $5.7 million, the resulting net increase of 143% shown in cell S20 increases to 199%.

[327] ETSWD's In. Br. at 8-10.

transmission charges resulting from Large Lighting Power customer sites[328] with behind-the-meter generation to SWEPCO customers without such onsite generation . . . ."[329] That is incorrect. ETSWD's citation for this misstatement is to a portion of the transcript in which Mr. Pollock explained his exhibit JP-4.[330] As Mr. Pollock explained at the hearing, however, this exhibit is simply an illustration of the impact of applying Mr. Pollock's cost-allocation proposals at SWEPCO's proposed revenue requirement, with Mr. Pollock's proposed revenue distribution.[331] This illustration assumes SWEPCO's full requested rate increase (including the \$5.7 million relating to BTMG), but puts to the side (for the moment) the question of how the SSGL charge should be handled (since Mr. Pollock opposes that charge).[332] Needless to say, Mr. Pollock does not support including any of the \$5.7 million in the Texas retail revenue requirement. Moreover, if SWEPCO's BTMG proposals are approved, Mr. Pollock has a specific recommendation as to how the resulting costs should be allocated. As set forth in his pre-filed testimony,[333] and as explained at the hearing, Mr. Pollock's proposal is that (1) a separate rate class should be created for BTMG loads, (2) a rate should be designed to recover the costs associated with those loads, and (3) the rate should be phased in at 50% in this case, given that it would otherwise result in rate shock.[334] In fact, Mr. Pollock even spelled out in his testimony that phasing in the SSGL charge at 50% would result in additional SSGL revenues of \$2.85 million (50% of \$5.7 million).[335] It is thus a mystery how ETSWD can claim that Mr. Pollock recommends shifting 90% of the costs

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[328] It is entirely unclear what ETSWD means by LLP customers "sites" plural, given that SWEPCO has only reported the BTMG load of one customer (Eastman), which purchases power under the standby rate schedule. TIEC Ex. 1, Pollock Dir. at 37, 39.

[329] ETSWD's In. Br. at 9.

[330] *Id.* (citing Tr. at 1350:22–1351:1 (Pollock Cross) (May 25, 2021)).

[331] Tr. at 1348:20-1350:12 (Pollock Cross) (May 25, 2021); Tr. at 1356:13-1357:16 (Pollock Redir.) (May 25, 2021); *see also* TIEC Ex. 1, Pollock Dir. at 46 (explaining that Exhibit JP-4 is a revenue allocation based on Mr. Pollock's recommended CCOSS).

[332] Tr. at 1348:12-1349:10 (Pollock Cross) (May 25, 2021).

[333] TIEC Ex. 1, Pollock Dir. at 39, 52-53.

[334] Tr. at 1359:3-1360:5 (Pollock Redir.) (May 25, 2021).

[335] *Id.*; TIEC Ex. 1, Pollock Dir. at 53.

associated with Eastman's BTMG to other rate classes.

ETSWD's arguments as to why moderation should be limited or not applied with respect to Eastman are equally unavailing.[336] ETSWD first argues that cost causation does not support shifting costs related to BTMG load onto customers that do not have BTMG.[337] But it is always the case that classes that are asked to absorb a revenue shortfall created by a gradualism constraint are charged for costs they did not cause. That is why it is called a subsidy. Indeed, ETSWD's complaints on this point are ironic, given that one of the classes it represents (Oilfield Secondary)[338] would receive a subsidy under SWEPCO's proposal in this case, which ETSWD supports.[339] Specifically, SWEPCO's rebuttal CCOSS shows that Oilfield Secondary should receive an 83.8% rate increase at equalized rates, but, after gradualism is applied, this class would receive a net increase of roughly half of that (42.93%).[340] At the hearing, ETSWD's witness Ms. Pevoto confirmed that her position is that the other members of SWEPCO's Commercial & Industrial group should pick up a subsidy to benefit Oilfield Secondary.[341] At the same time, however, she testified that any BTMG-related costs that are not directly borne by Eastman should be charged to LLP-T customers only, notwithstanding that she agrees that LLP-T customers other than Eastman did not cause any of those costs.[342] ETSWD's arguments regarding cost causation are inconsistent and self-serving, and have nothing to do with the proper application of moderation relating to BTMG costs in this case.

Finally, ETSWD argues that the gradualism inquiry should focused on the total bill "and

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[336] Given that ETSWD is arguing against a 90% cost-shifting proposal that Mr. Pollock did not actually make, it is unclear whether ETSWD opposes applying moderation to Eastman in the event SWEPCO's BTMG proposals are adopted.

[337] ETSWD's In. Br. at 9.

[338] Tr. at 1292:14-19 (Pevoto Cross) (May 25, 2021).

[339] ETSWD's In. Br. at 9.

[340] SWEPCO Ex. 55, Jackson Reb. at Exhibit JLJ-1R.

[341] Tr. at 1293:4-7 (Pevoto Cross) (May 25, 2021) (confirming she supports SWEPCO's moderation proposal); *id* at 1295:7-16 (agreeing that SWEPCO's moderation proposal includes a subsidy for Oilfield Secondary that major rate class commercial and industrial will pay).

[342] Tr. at 1297:19-1298:12 (Pevoto Cross) (May 25, 2021).

not line items like transmission cost assignment in isolation."[343] Needless to say, however, imposing a new massive charge on a customer can cause that customer's total bill to increase by a large amount. Indeed, Mr. Pollock's calculation of a 143% impact to Eastman from SWEPCO's proposal is calculated on the total base revenue increase, and as he explained in his testimony, "Applying this charge, ***coupled with SWEPCO's proposed increase to the standby rates***, would result in Eastman experiencing a 143% base revenue increase."[344] Ms. Jackson confirmed this calculation at the hearing,[345] and ETSWD has not disputed it. The record is clear that, if SWEPCO's BTMG proposal is adopted, the total-bill impact to Eastman will warrant moderation.

B. Rate Design and Tariff Changes [PO Issues 60, 61, 62]

TIEC addressed three issues relating to the LLP rate schedule in this section of its initial brief. First, the allocation of revenues to rates within the schedule should be based on the CCOSS results and reflect cost causation.[346] No party opposed that recommendation in initial briefing. Second, SWEPCO should implement a renewable energy credit (REC) opt-out tariff.[347] Third, SWEPCO's proposed increase to the reactive-power charge should be rejected as unsupported.[348] SWEPCO addressed the latter two points in its brief, and TIEC replies below.

2. REC Opt-Out Tariff[349]

SWEPCO's base rates include costs associated with RECs, but, under the Commission's rules, transmission-voltage customers that opt out are not required to pay for those costs.[350]

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343 ETSWD's In. Br. at 9.

344 TIEC Ex. 1, Pollock Dir. at 51 (emphasis added); *see also* TIEC Ex. 1A, Pollock Dir. Workpapers at "WP Eastman Impact TIEC_11-7_Attachment_1.xslx." As explained in citations, TIEC's calculations of the impact of the rebuttal charge, and of applying the entire $5.7 million to Eastman, are based on this calculation of base revenue impacts.

345 Tr. at 1251:21-15 (Jackson Cross) (May 25, 2021).

346 TIEC's In. Br. at 82; *see also id.* at 79 (describing revenue distribution during rate-design process).

347 *Id.* at 82-83.

348 *Id.* at 83-84.

349 SWEPCO addresses this issue in Section VII.D.2. SWEPCO's In. Br. at 129.

350 16 T.A.C. § 25.173(j).

Accordingly, it is necessary to establish a REC opt-out provision to credit transmission customers who submit opt-out notices. SWEPCO agrees with this, but its calculation of the credit factor is flawed because it is based on a demand allocation.[351] Mr. Pollock properly calculated his REC energy credit, which is 0.064 cents per kWh, based on an energy allocation.[352]

SWEPCO offers no support for a demand-based allocation, stating only that "[t[he allocation is demand-based because the REC value is recorded in FERC Account 555 and the credit factor is developed based on kWh sales at the meter for eligible customers."[353] But RECs are energy-related. In fact, RECs accrue on a per-MWh basis, as SWEPCO itself acknowledges in describing its REC rider.[354] The Commission's rule on RECs defines them as representing "one MWh of renewable energy."[355] SWEPCO's mere recitation that the REC value is recorded in FERC Account 555 (which is the FERC account for purchased power) does not indicate that RECs should be treated as demand-based.[356] Purchased power expenses can be demand- or energy-based. Mr. Pollock's REC opt-out credit calculation should be adopted.

3. Reactive Demand Charge

SWEPCO proposes to increase its reactive demand charge by nearly 30% but has not provided any cost-based evidence to support the need for a change in that charge.[357] SWEPCO admits in its brief that it has not performed a separate reactive demand study but states that this is "because the reactive demand charge is encompassed within and is part of overall cost increase."[358]

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[351] SWEPCO's In. Br. at 129.

[352] TIEC Ex. 1, Pollock Dir. at 50; TIEC Ex. 1A, Pollock Dir. Workpapers, Workpaper "LLP-T REC Opt-out."

[353] SWEPCO's In. Br. at 129.

[354] *Id.* at 128 ("These certificates are issued when one megawatt-hour (MWh) of electricity is generated and delivered to the grid from a renewable energy source."); *see also* SWEPCO Ex. 32, Jackson Dir. at 30.

[355] 16 T.A.C. § 25.173(c)(13).

[356] *See* 18 C.F.R. § Pt. 101, 555(A) ("This account shall include the cost at point of receipt by the utility of electricity purchased for resale . . . .").

[357] TIEC Ex. 1, Pollock Dir. at 49.

[358] SWEPCO's In. Br. at 126.

That argument is entirely circular. The question before the Commission is whether SWEPCO has met its burden of proving that the reactive demand charge should be increased. Reactive power is a different type of power than real power,[359] and the purpose of a reactive demand charge is to recover costs associated with addressing customers with a low power factor.[360] SWEPCO has provided no evidence that the current reactive demand charge is inadequate to recover the relevant costs associated with reactive power. Therefore, the proposed increase should be rejected.

C. Transmission Rate for Retail Behind-the-Meter Generation

SWEPCO's proposed SSGL charge should be rejected.[361] The charge would apply to service that SWEPCO does not actually provide—transmission service to customers who serve their own load with BTMG.[362] The charge is based on, as Eastman aptly puts it, "phantom load" that does not reflect actual costs imposed on the transmission network at the time of peak.[363] Moreover, the charge would apply only to Eastman's phantom load because SWEPCO has not reported the phantom load of any of the nearly 200 other retail BTMG customers it has in Texas (or of any of the BTMG customers it has in other states).[364] SWEPCO's proposed SSGL charge is thus unreasonable and discriminatory. As set out in TIEC's initial brief, if the Commission nevertheless approves a charge for BTMG service, it should (1) create a separate class for retail BTMG loads; (2) design a rate to recover the costs associated with that "service"; (3) that is based on the customer's demand coincident with the SPP Zone 1 monthly peak; and (4) for purposes of this case, implement a 50% phase-in to moderate the impact to the only customer to whom the charge would currently apply, Eastman.[365]

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[359] *E.g.*, 16 T.A.C. § 25.278(e)(2)(T).

[360] For example, the Commission's rules define "Transmission service" to include "reactive power support." 16 T.A.C. § 25.5(139).

[361] TIEC reiterates that the charge should be rejected for all of the reasons TIEC discussed in Sections IV.A.6, and VI.A-B in both its initial and reply briefs.

[362] TIEC Ex. 1, Pollock Dir. at 52.

[363] Eastman's In. Br. at 22; Tr. at 1167:26-21, 1188:12-22 (Ross Cross) (May 25, 2021).

[364] TIEC Ex. 2, Pollock Supp. Dir. at JP-S1.

[365] TIEC's In. Br. at 86-89.

SWEPCO's brief does not truly grapple with the problems with its proposed SSGL charge.[366] As discussed above, SWEPCO allocates approximately $8 million to LLP-T to account for Eastman's BTMG load, but SWEPCO's direct-case SSGL charge is designed to recover $3.96 million from Eastman, while its rebuttal-case SSGL charge is designed to recover $3.27 million.[367] SWEPCO never explains why it is appropriate to leave the remaining amounts to be recovered by LLP-T customers other than Eastman, particularly given Ms. Jackson's testimony that these customers already pay for their share of SWEPCO's transmission system through the LLP-T demand charge.[368] Further, while SWEPCO has not directly assigned the costs it attributes to including Eastman's BTMG load in its SPP reports, its direct-case proposal would increase Eastman's total base rates by 143%, and the rebuttal increase would be 121%.[369] But SWEPCO does not explain why those results would be reasonable or not visit rate shock on a customer, particularly one that has already made substantial investments in its own BTMG. Notably, SWEPCO general moderation proposal in this case is to cap increases at 43%.[370]

While SWEPCO has failed to explain these flaws in its proposal, it does indicate that it is willing to implement a solution that the Commission finds fair and reasonable.[371] In this connection, SWEPCO designed the rebuttal charge such that it could apply to a BTMG customer in any rate class.[372] And, as Ms. Jackson testified at the hearing and as SWEPCO confirms in its brief, SWEPCO agrees that it would be reasonable and appropriate to create a separate rate schedule on a separate tariff sheet for its rebuttal SSGL rate.[373] To the extent that the Commission

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[366] SWEPCO's In. Br. at 126-28.

[367] TIEC Ex. 1, Pollock Dir. at 51; Tr. at 1504:22-1505:4 (Jackson Cross) (May 26, 2021).

[368] *See* Tr. at 1254:2-10 (Jackson Cross) (May 25, 2021).

[369] TIEC Ex. 1A, Pollock Dir. Workpapers at "WP Eastman Impact TIEC_11-7_Attachment_1.xslx." If the $2.20/kW charge in cell C19 in this spreadsheet is changed to $1.82/kW, the resulting net increase of 143% shown in cell S20 decreases to 121%.

[370] SWEPCO's In. Br. at 122.

[371] *Id.* at 127.

[372] SWEPCO Ex. 55, Jackson Reb. at 14.

[373] SWEPCO's In. Br. at 128; Tr. at 1508:19-1509:3 (Jackson Re-cross) (May 26, 2021).

authorizes any BTMG charge of this type, it would indeed be appropriate for it to constitute its own rate schedule.[374] If one fully indulges the counter-factual that SWEPCO actually provides this SSGL service to customers who serve their own load, it becomes clear that it would not be a standby service as SWEPCO originally proposed. It would be a year-round unbundled network transmission "service" provided to retail BTMG customers that is unlike any other full-requirements service that SWEPCO provides.[375] Thus, if the Commission were to adopt such a charge, it should treat the BTMG loads as a separate class as Mr. Pollock proposes.

ETSWD repeats in this section of its brief that it does not believe that any customers that do not have BTMG load should be assigned any BTMG-related costs,[376] though that concern apparently does not extend to the LLP-T customers who do not have such load. TIEC generally agrees that, if the Commission approves charging retail BTMG customers for network transmission service (that they do not actually receive), it should create a separate rate class and then design a rate to recover costs associated with that service. There would of course be a need for moderation in this case, however. As indicated above, Eastman would receive a 143% increase at SWEPCO's direct-case SSGL charge, a 121% at SWEPCOs rebuttal case SSGL, and nearly 200% if the entire $5.7 million SWEPCO attributes to BTMG-related costs were directly assigned.[377] Given this potential for rate shock, and given the unprecedented and imprecise nature of this charge, gradualism is appropriate, with the impact of the subsidy being absorbed by all non-capped rate classes.[378]

ETSWD's opposition to moderating the rate impact to Eastman under these circumstances rings hollow, particularly given that ETSWD has been an aggressive advocate for gradualism for its own benefit. In fact, Ms. Pevoto confirmed at the hearing that while, on the one hand she

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[374] TIEC Ex. 1, Pollock Dir. at 54; Tr. at 1508:19-1509:3 (Jackson Re-cross) (May 26, 2021).

[375] TIEC Ex. 1, Pollock Dir. at 54.

[376] ETSWD's In. Br. at 10-11.

[377] TIEC Ex. 1A, Pollock Dir. Workpapers at "WP Eastman Impact TIEC_11-7_Attachment_1.xlsx." If the $3.96 million recovered under the SSGL in cell R19 in this spreadsheet is changed to $5.7 million, the resulting net increase of 143% shown in cell S20 increases to 199%.

[378] TIEC's In. Br. at 88.

believes that all costs associated with Eastman's BTMG load should stay within the LLP-T class (notwithstanding that she also agrees that LLP-T customers other than Eastman did not cause those costs), she also believes on the other hand that all members of the major Commercial & Industrial rate grouping should subsize Oilfield Secondary.[379] Indeed, ETSWD states that it supports SWEPCO's rebuttal gradualism methodologies, which include a 43% rate-increase cap.[380] Nevertheless, it appears to be ETSWD position is that Eastman should be subject to a total base rate increase of well over 100% without any moderation.[381] ETSWD's selective support for gradualism and rate subsidies is without merit.

VIII. Baselines for Cost-Recovery Factors [PO Issue 4, 5, 52, 63]

In their initial briefs, SWEPCO and Staff both urge the adoption of baselines for the TCRF, DCRF, and GCRR based on their respective CCOSSs.[382] TIEC would simply clarify that the baselines adopted in this case should reflect the Commission's decisions on the applicable revenue requirement and cost allocation/rate design issues. TIEC's positions on those issues are addressed throughout its briefing.

XI. Conclusion

TIEC respectfully requests that the Commission adopt the positions set out above and in its initial brief.

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379 Tr. at 1306:16-20 (Pevoto Recross) (May 25, 2021).

380 ETSWD's In. Br. at 8-9; SWEPCO Ex. 55, Jackson Reb. at 8; Tr. at 1247:14-1248:1 (Jackson Cross) (May 25, 2021).

381 ETSWD's In. Br at 8-9.

382 SWEPCO's In. Br. at 129-31; Staff's In. Br. at 79.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I, Benjamin B. Hallmark, Attorney for TIEC, hereby certify that a copy of the foregoing document was served on all parties of record in this proceeding on this 1st day of July 2021 by hand-delivery, facsimile, electronic mail and/or First Class, U.S. Mail, Postage Prepaid.

/s/ Benjamin B. Hallmark

Benjamin B. Hallmark

Attachment A

Source: TIEC Ex. 74 (SWEPCO's Response to TIEC 11-1, Attachment 1)

		RESIDENTIAL		COMMERCIAL							INDUSTRIAL							MUNICIPAL		LIGHTING			
								-------- LIGHT & POWER --------			--------- LLP ---------												
														METAL MELTING									
Class		BASIC	DG	W/DEMAND	GS WO/DEMAND	COTTON GIN	DG	SEC	PRI	DG SEC	PRI	TRAN	OILFIELD PRIMARY	PRI	TRANS	SEC	OILFIELD SEC	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC & HWY LIGHTING	PRIVATE AREA LIGHTING	CUST-OWNED LIGHTING
With Eastman	REVENUE DEFICIENCY / (SURPLUS)	41.055.229	19 427	3.884 167	2.247 226	244.080	2 746	36 194 917	3.971.269	154 581	1 590 320	9.147 516	3,643,272	526.501	81.464	53.205	507.957	401,037	(27,445)	397.616	68.554	751,957	110,641
Without Eastman	REVENUE DEFICIENCY / (SURPLUS)	41,441,339	21,303	3,897,779	2,251,850	247,349	2,830	37102868 8	4,378,883	156,971	1,673 533	1,191,277	3,909,031	552,537	117,667	54,625	518,989	444,024	(12 021)	416,239	69,321	787,334	115,442
		(386,110)	(1.876)	(13,612)	(4,623)	(3.269)	(83)	(907,951)	(407,615)	(2,390)	(83 213)	7.956,240	(265,759)	(26.036)	(36 203)	(1.421)	(11.032)	(42,988)	(15.424)	(18.623)	(67)	(35.376)	(4 801)